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

April 21, 2010

Mr. Charles G. Pardee
Senior Vice President, Exelon Generation Company, LLC
President and Chief Nuclear Officer (CNO), Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000373/2010002; 05000374/2010002

Dear Mr. Pardee:

On March 31, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your LaSalle County Station, Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed on April 14, 2010, with the Site Vice President, Mr. Dave Wozniak, and other members of your staff.

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

Based on the results of this inspection, two findings of very low safety significance were identified. These findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest the subject or severity of a NCV, 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 a copy 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 Resident Inspector Office at the LaSalle County Station. In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the LaSalle County Station. The information that you provide will be considered in accordance with Inspection Manual Chapter 0305.

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 (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA By Nirodh Shah Acting For/

Kenneth Riemer, Chief
Branch 2
Division of Reactor Projects

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

Enclosure: Inspection Report 05000373/2010002; 05000374/2010002
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000373; 05000374
License Nos:	NPF-11; NPF-18
Report No:	05000373/2010002; 05000374/2010002
Licensee:	Exelon Generation Company, LLC
Facility:	LaSalle County Station, Units 1 and 2
Location:	Marseilles, IL
Dates:	January 1, 2010, through March 31, 2010
Inspectors:	G. Roach, Senior Resident Inspector F. Ramírez, Resident Inspector M. Holmberg, Reactor Inspector M. Mitchell, Region III Health Physics Inspector C. Scott, Region III Reactor Engineer P. Smagacz, Region III Reactor Engineer A. Scarbeary, Region III Reactor Engineer J. Corujo-Sandín, Reactor Inspector J. Yesinowski, Illinois Dept. of Emergency Management B. Metrow, Illinois Dept. of Emergency Management
Approved by:	Kenneth Riemer, Chief Branch 2 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000373/2010-002, 05000374/2010-002; 01/01/2010 - 03/31/2010; LaSalle County Station, Units 1 & 2; Maintenance Effectiveness and Refueling Outage.

The report covers a 3-month period of inspection by the resident inspectors and announced inspection by a regional health physics inspector and a regional in-service inspector.
Two Green findings, both of which were non-cited violations (NCVs), were identified.
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 U.S. Nuclear Regulatory Commission (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 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. A finding of very low safety significance was self-revealed with the unit in the refueling mode of operation. Specifically, operations and maintenance personnel did not establish proper field communications while testing excess flow check valves (EFCV) as required by procedure and consequently operated the wrong component. As a result, a Division 2 emergency core cooling system (ECCS) signal was received and control room operators were subjected to an unnecessary operational distraction. A NCV of Section 10 of the Code of Federal Regulations (CFR) Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was also identified for failure to appropriately implement procedure LIS-NB-115B, "Unit 1 High Pressure Excess Flow Check Valve Operability Test."

  The inspectors determined that the finding was more than minor because it affected the Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety function during shutdown as well as power operations. It also affected the Human Performance Cornerstone attribute due to the multiple errors associated with field communications and procedure use and affected the Configuration Control attribute for shutdown lineup. Specifically, by not following the procedure as written, personnel in the field created an unnecessary operational distraction in the control room while other significant activities, such as refueling operations, were in progress. The finding was determined to be of very low safety significance using the SDP Phase 1. This finding is also related to the cross-cutting area of Human Performance (work practices) because the procedure in question was not followed. Corrective actions planned and completed by the licensee included halting all EFCV testing until an initial investigation into the event was performed and conducting an apparent cause evaluation for the event. (Section 1R20)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance for the licensee's failure to ensure the standby liquid control (SBLC) system could mitigate the consequences of all design basis anticipated transient without scram (ATWS) events. Specifically, the licensee lowered SBLC pump discharge relief valve set pressure to a value where a successful relief valve surveillance test result could be achieved, but SBLC system pressure attained during certain ATWS events would result in lifting the relief valve, which redirects the required sodium pentaborate solution away from the reactor. A NCV of 10 CFR 50, Appendix B, Criterion III, “Design Control,” was also identified for failure to maintain the design basis of the SBLC system to bring the reactor from rated power to a cold shutdown condition at any time in core life as described in the Updated Final Safety Analysis Report (UFSAR).

The inspectors determined that the finding was more than minor because it affected the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. In addition, the finding affected the attribute of design control in the area of plant modifications. Specifically, by changing the set pressures of the SBLC relief valves, the licensee created the possibility that an SBLC train would not be capable of injecting neutron absorber solution into the reactor to accomplish the above stated design specification under certain accident conditions. The finding was determined to be of very low safety significance using the SDP Phase 3. As part of their corrective actions, the licensee adjusted the relief valve setpoints and is performing a detailed root cause on the set pressure drift phenomenon and the maintenance and testing practices performed by licensee personnel on the relief valves in question. (Section 1R12)

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

None.

REPORT DETAILS

Summary of Plant Status

Unit 1

The unit began the inspection period operating at full power. On January 3, 2010, power was reduced to approximately 70 percent for control rod pattern adjustment and was restored to 100 percent that same day. On January 15, 2010, power was reduced to approximately 60 percent to repair a leak in the main condenser west tube bundle. Following repairs, the unit was returned to full power on January 18, 2010. On January 22, 2010, power was reduced to approximately 70 percent for control rod pattern adjustment and was returned to full power that same day. On January 29, 2010, the unit commenced coastdown for refueling outage (RFO) L1R13. On February 7, 2010, a normal unit shutdown was performed to begin L1R13. Following completion of the outage, the Unit 1 main generator was synchronized to the grid. Full power was achieved on March 9, 2010, where it remained for the rest of the inspection period.

Unit 2

The unit began the inspection period at full power. On March 21, 2010, power was reduced to approximately 78 percent for control rod pattern adjustment. The unit was restored to full power on March 21, 2010, where it remained for the remainder of the inspection period.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

.1 Readiness for Impending Adverse Weather Condition – Heavy Snowfall Conditions

a. Inspection Scope

On January 6, 2010, a winter-weather advisory was issued for expected snow squalls. The inspectors observed the licensee’s preparations and planning for the significant winter weather potential. The inspectors reviewed licensee procedures and discussed potential compensatory measures with control room personnel. The inspectors focused on plant management’s actions for implementing the station’s procedures for ensuring adequate personnel for safe plant operation and emergency response would be available. The inspectors conducted a site walkdown including walkdowns of various plant structures and systems to check for maintenance or other apparent deficiencies that could affect system operations during the predicted significant weather. The inspectors also reviewed corrective action program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station CAP procedures. In this inspection, no documents were identified which required further review.

This inspection constituted one readiness for impending adverse weather condition sample as defined in inspection procedure (IP) 71111.01-05.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- 1B residual heat removal (RHR) service water (SW) during 1A train testing;
- Unit 2 reactor core isolation cooling (RCIC); and
- Unit 1 high pressure core spray (HPCS) piping configuration concerning non-condensable gas intrusion and accumulation [Temporary Instruction (TI) -177].

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

These activities constituted three partial system walkdown samples as defined in IP 71111.04-05. Also, additional activities were performed during this system walkdown that were associated with TI 2515/177, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems,” as described in the third bullet of this section.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Unit 1, reactor building (fire zone 2G), 710 foot elevation;
- Unit 1, reactor building (fire zone 2F), 740 foot elevation;
- Unit 2, reactor building (fire zone 3F), 740 foot elevation; and
- Unit 1, turbine building (fire zone 5B4), 735 foot elevation.

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan.
The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment, which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the Attachment to this report, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP. Documents reviewed are listed in the Attachment to this report.

These activities constituted four quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings of significance were identified.

1R07 Annual Heat Sink Performance (71111.07)

.1 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the licensee's testing of the 1A residual heat removal heat exchanger to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors reviewed the licensee's observations as compared against acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. Inspectors also verified that test acceptance criteria considered differences between test conditions, design conditions, and testing conditions. Documents reviewed for this inspection are listed in the Attachment to this report.

This annual heat sink performance inspection constituted one sample as defined in IP 71111.07-05.

b. Findings

No findings of significance were identified.

1R08 In-service Inspection Activities (71111.08)

From February 10 through 17, 2010, the inspectors conducted a review of the implementation of the licensee's in-service inspection (ISI) program for monitoring degradation of the reactor coolant system, emergency feedwater systems, risk-significant piping and components and containment systems.

The inspections described in the Piping Systems ISI Section and Identification and Resolution of Problems Section below constituted one inspection sample as defined in IP 71111.08.

.1 Piping Systems ISI

a. Inspection Scope

The inspectors observed the following nondestructive examinations (NDEs) required by the American Society of Mechanical Engineers, (ASME) Section XI Code to evaluate compliance with the ASME Code, Section XI, applicable ASME Code Cases and Section V requirements, and if any indications and defects were detected, to determine if these were dispositioned, in accordance with the ASME Code or an NRC-approved alternative requirement:

- manual ultrasonic examination (UT) of reactor pressure vessel (RPV) nozzle-to-shell weld LCS-1-N6A; and
- visual VT-3 examination of main steam snubber support MS 001011S.

The inspectors observed the following NDEs conducted as part of the licensee's industry initiative inspection programs for managing vessel internals cracking and intergranular stress corrosion cracking to determine if the examinations were conducted in accordance with the licensee's augmented inspection program, industry guidance documents and associated licensee examination procedures and, if any indications and defects were detected, to determine if these were dispositioned in accordance with approved procedures and NRC requirements:

- automated phased array UT of nozzle-to-safe end extension piece weld (LP-1001-33B) and nozzle-to-safe end weld (RH-1004-35A) in accordance with boiling water reactor (BWR) vessel internals project 75a "BWRVIP-75-A: BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules.";
- in-vessel visual examination of jet pump wedges No. 5 and No. 18l, in accordance with BWRVIP-41 "BWR Vessel Internals Project BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines"; and
- visual examination of steam dryer vertical weld 8a, in accordance with BWRVIP 139 "BWR Vessel and Internals Project Steam Dryer Inspection and Flaw Evaluation Guidelines."

The inspectors reviewed the following examination records with relevant/recordable conditions/indications identified by the licensee to determine if acceptance of these indications for continued service was in accordance with the ASME Code Section XI or an NRC-approved alternative:

- Report No. L1R-12-002, RPV Head-to-Flange Weld GE:-1009-AG-MT; and
- Report No. L1R-12-029, RPV Washers Coating Loss.

The inspectors observed portions of the following pressure boundary welds completed for a risk significant system to determine if the licensee followed an ASME Code Section IX qualified welding procedure, maintained control of foreign material, and to determine if the welder used qualified weld filler material and base material. The inspectors also reviewed post-weld NDE records, to determine if the welds met the ASME Code Sections III and XI:

- field weld No. 1 fabricated during the replacement of the 18-inch diameter core standby cooling valve 1E12-F330C; and
- field weld No. 1 fabricated during the replacement of the 18-inch diameter core standby cooling valve 1E12-F330D.

b. Findings

No findings of significance were identified.

.2 Identification and Resolution of Problems

a. Inspection Scope

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

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

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

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On March 11, 2010, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

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

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

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

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- SBLC system transitioned to maintenance rule (a) (1) status; and
- switchyard maintenance program.

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

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

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

This inspection constituted two quarterly maintenance effectiveness samples as defined in IP 71111.12-05.

b. Findings

Introduction: A finding of very low safety significance and associated NCV of 10 CFR 50, Appendix B, Criterion III, Design Control was identified by the inspectors for the licensee's failure to ensure the SBLC system could mitigate the consequences of all design basis ATWS events. Specifically, the licensee lowered SBLC pump discharge relief valve set pressure to a value where a successful relief valve surveillance test result could be achieved, but SBLC system pressure attained during certain ATWS events would result in lifting the relief valve, which redirects the required sodium pentaborate solution away from the reactor.

Description: In 1994, the licensee adjusted the set pressure of the Unit 1 and Unit 2 SBLC relief valves from 1400 to 1340 psig with a tolerance of plus or minus 3 percent. The licensee performed this modification in an effort to comply with the SBLC Standard TS requirement that the relief valves be set at less than or equal to 1400 psig. The Improved Standard TS LaSalle is currently licensed to do not have such a requirement.

The SBLC relief valves remained at the lower set pressure until the fall of 2009 when during the performance of a margin uncertainty recovery power uprate analysis for the ATWS accident, the licensee identified that the SBLC system pressures experienced during the main steam isolation valve (MSIV) closure ATWS event would exceed pressures within the allowable pressure band for the SBLC relief valves. In this circumstance, the lifting SBLC relief valve would recirculate the sodium pentaborate solution needed to shutdown the reactor and not send it to the reactor vessel as the

SBLC design requires in order to respond to an ATWS event. The licensee performed Operability Evaluation 09-003, in order to address the operability of the SBLC trains with the lower relief valve set pressure band. The licensee determined that the four SBLC trains (two per unit) remained operable because recent in-service test (IST) data showed the lowest relief valve test result was 1308 psig. The maximum pressure experienced in the SBLC system was determined to be 1306 psig during the MSIV closure ATWS. In addition, the inspectors identified that the present set pressure tolerance would allow a relief valve to lift as low as 1300 psig and be considered to have performed satisfactorily. The licensee determined that this margin was unacceptable and created a WO to change the set pressure of the SBLC relief valves back to 1400 psig plus or minus 3 percent.

On December 3, 2009, the relief valve from the 2B SBLC train was removed to have its set pressure adjusted to the higher pressure band. The valve was bench tested to determine the as-found lift pressure. The valve lifted at 1278 psig, which was considered unsatisfactory per ASME code requirements, and also affected operability of the 2B SBLC train. The licensee had already considered the 2B train inoperable while the relief valve was removed and had already entered the appropriate TS action statement for a single inoperable SBLC train. With no obvious failure mechanism for the valve, the licensee procedures consider the failure to have occurred at the time of discovery. Therefore, no loss of safety function existed, as the 2A SBLC was considered operable. Licensee failure analysis for the 2B SBLC relief valve identified no failed component, thus setpoint drift was identified as the most likely cause of the valve failure. ASME Class 2 relief valves are required to be lift tested at a periodicity not to exceed once every 10 years. This was the practice at LaSalle, so a maximum of 10 years between lifts could occur for these valves. The valve in question had been previously tested in September 2001.

The inspectors reviewed the licensee’s assessment of the failure and the ASME code required follow-on actions for a failed-as-found test. The inspectors expanded the scope of valve testing data to include as-found test data for all seven relief valves cycled through the SBLC trains dating back to 1998. During that time, 11 valve failures occurred during 36 tests. Ten of the 11 had no immediate failure mechanism and were considered to be associated with setpoint drift. The 11th event was a fatigue failure associated with the valve’s pressure bellows which occurred in October 2009.
The licensee determined that during historical quarterly SBLC pump testing, the operators had been causing the relief valves to chatter open and closed while establishing the system conditions for testing. Starting in 2007, the licensee made a number of design and procedural changes which successfully prevented the relief valves from lifting during routine testing. The inspectors considered the performance deficiency associated with this failure to be not representative of present performance as an installed relief valve had not lifted during testing in more than two years. Of the failures tied to setpoint drift, seven had drifted high out of band or did not lift at all. Three of the failures (including the December 3rd event) were low out of band. The inspectors noted that the licensee had not considered the first two failures that were low out of tolerance for train operability as they were performed on a valve that had been installed in a Unit 2 train in 1999 when this unit was in an extended period of shutdown and SBLC would not have been required to be operable and the second failure, also occurring in 1999, was performed on a valve that had been previously in stores and not recently installed in the plant. This data was also not considered in Operability Evaluation 09-003. As a result, the licensee did not recognize that SBLC relief valves had a history of failure that

included drift in the low direction, which would place the train's ability to respond to certain ATWS events into question.

In order to address the set pressure implications for ATWS, the licensee changed the set pressures of all presently installed SBLC relief valves to 1400 psig plus or minus 3 percent. In addition, the licensee performed the scope expansion testing of SBLC relief valves required by ASME OM Code-2001 Section I-1350. Follow-on testing has resulted in two additional testing failures. Neither of these failures challenged SBLC ability to mitigate an ATWS. The licensee has chartered a root cause team and has brought in the valve vendor to review maintenance and testing practices.

Analysis: The inspectors determined that establishing and operating with relief valve set pressures which would prevent the SBLC system from mitigating certain design basis ATWS events was a performance deficiency.

The finding was determined to be more than minor because it affected the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically the finding affected the attribute of design control in the area of plant modifications.

The inspectors reviewed Inspection Manual Chapter (IMC) 0609, Attachment 4, and performed a Phase 1 SDP screening under the Mitigating Systems Cornerstone in the area of reactivity control. The inspectors answered "yes" to Mitigating Systems question three because the December 3, 2009, relief valve failure constituted a single train inoperability of greater than the TS allowed outage time. Answering "yes" to question three required the inspectors to perform a phase 2 SDP evaluation under IMC 0609, Appendix A. Using the licensee's assessment that the failure mechanism for the SBLC relief was setpoint drift, the inspectors assumed a linear drift over the time period between testing. The inspectors determined that based on the successful lift test of 1330 psig in September 2001 and the failed lift of 1278 psig in December 2009; the valve set pressure would have degraded below the maximum ATWS pressure of 1306 psig approximately 53 months ago. Less conservatively, the T/2 methodology (half the time between subsequent tests) of identifying inoperability would have assumed approximately 49 months of inoperability. Using this information, the inspectors utilized the LaSalle Unit 2 pre-solved work sheet for one train of SBLC inoperable for longer than one year. The result indicated a finding of substantial safety significance or Yellow. Because of inherent conservatisms assumed in the Phase 2 analyses, the inspectors contacted the region-based Senior Reactor Analyst (SRA) for LaSalle, who performed further risk analyses via a Phase 3 risk assessment.

The SRA performed the Phase 3 analysis using the LaSalle Standard Plant Analysis Risk Model, Revision 3P, Level 1, Change 3.45, dated November 2009. The SRA modeled this performance deficiency as failure of Train B of the SBLC System. Specifically, the SRA modeled the issue as failure of the Train B SBLC pump. The SRA assumed an exposure time of one year, the maximum period allowed in SDP analyses. The resultant change in core damage frequency was 2.0E-7 per year. The dominant core damage sequence involved a "transient" (i.e., reactor scram) with subsequent failure of the reactor protection system (RPS) (termed an "Anticipated Transients Without Scram (ATWS)" event), and SBLC. Remaining successful mitigating capability included the reactor recirculation (RR) system, safety relief valves, and power conversion (turbine bypass).

Because the above risk was greater than 1.0E-7, the SRA evaluated the external and large early release frequency (LERF) risk contribution. External event contribution (fire, floods, winds) were deemed insignificant to the risk of the finding since the frequency of ATWS events resulting from these external events would be much lower than the frequency of the ATWS event itself. Regarding LERF, the LERF factors were listed as 0.4 in the LaSalle Phase 2 Risk-Informed Notebook. Thus, the change in risk due to LERF was calculated at 8.0E-8/yr. Considering this information, the risk significance of the finding is best characterized as Green.

Enforcement: 10 CFR 50, Appendix B, Criterion III, Design Control required, in part, that design changes, including field changes, be subject to design control measures. In addition, it required, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis for those SSCs to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions.

Contrary to the above, the licensee failed to maintain the design basis of the SBLC system to bring the reactor from rated power to a cold shutdown condition at any time in core life as described in UFSAR chapter 9.3. Specifically, by changing the set pressures of the SBLC relief valves, the licensee created the possibility that an SBLC train would not be capable of injecting neutron absorber solution into the reactor to accomplish the above stated design specification under certain accident conditions. Once identified, the licensee adjusted the relief valve setpoints and is performing a detailed root cause on the set pressure drift phenomenon and the maintenance and testing practices performed by licensee personnel on the relief valves in question. The licensee has entered this condition into their CAP as Issue Reports (IRs) 1000566, 1001151, and 1014305. Because this violation was of very low safety significance and it was entered into the licensee’s CAP, this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000373/2010002–01; 05000374/2010002–01, Failure to Maintain Design Control of SBLC system).

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- 1B RR pump motor move contingency plan – Orange Risk;
- station auxiliary transformer (SAT) failure and emergent repairs;
- 1B diesel generator (DG) fuel line failure; and
- protected equipment walkdown for yellow risk on Unit 1 during 1A SBLC relief valve replacement.

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

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

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- jet pump vibrations and there impact on total core flow;
- Unit 1B, SBLC relief valve failed to lift during periodic testing;
- allowable flow margin during ASME IST;
- hydraulic control unit (HCU) fasteners seismic non-conformance;
- 0 DG cooling water pump biennial testing methodology;
- divisional ECCS response time testing methodology; and
- 1B RHR shutdown cooling alternate configuration.

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

This operability inspection constituted seven samples as defined in IP 71111.15-05.

b. Findings

No findings of significance were identified.

1R18 Plant Modifications (71111.18)

.1 Permanent Plant Modifications

a. Inspection Scope

The following engineering design packages were reviewed and selected aspects were discussed with engineering personnel:

- Unit 1 core standby cooling system (CSCS) valve replacements; and
- the HPCS vent line addition at elbow upstream of injection valve.

Documents were reviewed for adequacy of the associated 10 CFR 50.59 safety evaluation screening, consideration of design parameters, implementation of the modification, post-modification testing, and relevant procedures, design, and licensing documents were properly updated. The inspectors observed ongoing and completed work activities to verify that installation was consistent with the design control documents. The Unit 1 CSCS system was modified to include replacement of Division II diesel cooling water pump and RHR SW pump suction valves and piping. The original carbon steel components were replaced by stainless steel components to mitigate the effects of corrosion and to prevent stem-disc separation of the various pump suction valves. The Unit 1 HPCS system was modified to add a vent line to the injection line at a high point upstream of the injection valve. Gas bubbles had previously accumulated at this location due to the historical piping configuration. Documents reviewed in the course of this inspection are listed in the Attachment to this report.

Also, additional activities were performed during the evaluation of the engineering design package that were associated with TI 2515/177, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems.” This activity is described in IR18, Section .2.

This inspection constituted two permanent plant modification samples as defined in IP 71111.18-05.

b. Findings

No findings of significance were identified.

.2 Permanent Plant Modifications associated with Temporary Instruction (TI) 2515/177, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems.”

a. Inspection Scope and Documentation

The following engineering design package associated with the scope of GL 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and

Containment Spray Systems," was reviewed and selected aspects were discussed with engineering personnel:

- HPCS vent line addition at elbow upstream of injection valve.

The inspectors verified that the licensing basis verification documents have either been updated or are in the process of being updated to reflect the modifications associated with the licensee's resolution of GL 2008-01 (TI 2515/177, Section 04.01). The verified documents included Technical Specifications (TS), TS Bases, updated final safety analysis report (UFSAR), and licensee-controlled documents and bases, such as the Technical Requirements Manual (TRM).

In addition, the inspectors verified that the drawings were up-to-date with respect to recent hardware changes and that any discrepancies between as-built configurations and the drawings were documented and entered into the Corrective Action Program for resolution (TI 2515/177, Section 04.02.a.6).

Similarly, the inspectors verified that Piping and Instrumentation Diagrams (P&IDs) accurately described the subject systems, that they were up-to-date with respect to recent hardware changes, and any discrepancies between as-built configurations, the isometric drawings, and the P&IDs were documented and entered into the CAP for resolution (TI 2515/177, Section 04.02.b).

Documents reviewed are listed in the Attachment to this report.

This inspection effort counts towards the completion of TI 2515/177 which will be closed on a later Inspection Report.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- Unit 1B SBLC pump discharge relief valve following setpoint adjustment;
- Unit 2A low frequency motor generator following breaker replacement;
- Unit 1A DG startup load acceptance testing;
- Unit 1B RR pump following installation of a new rotating element;
- Unit 1 SAT return to service;
- ID RHR SW pump IST baseline testing following pump replacement; and
- reactor control management system (RCMS) post-modification testing.

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

This inspection constituted seven PMT samples as defined in IP 71111.19-05.

b. Findings

No findings of significance were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the outage safety plan (OSP) and contingency plans for the L1R13 Unit 1 RFO, conducted February 8 to March 6, 2010, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the RFO, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over these outage activities:

- licensee configuration management, including maintenance of defense-in-depth commensurate with the OSP for key safety functions and compliance with the applicable TS when taking equipment out-of-service;
- implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing;
- installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error;
- controls over the status and configuration of electrical systems to ensure that TS and OSP requirements were met, and controls over switchyard activities;
- monitoring of decay heat removal processes, systems, and components;
- controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system;
- reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.

- controls over activities that could affect reactivity;
- maintenance of secondary containment as required by TS;
- refueling activities, including fuel handling and sipping to detect fuel assembly leakage;
- startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the drywell (primary containment) to verify that debris had not been left which could block ECCS suction strainers, and reactor physics testing;
- licensee compliance with NRC regulations concerning work hours for covered workers; and
- licensee identification and resolution of problems related to RFO activities.

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

This inspection constituted one RFO sample as defined in IP 71111.20-05.

b. Findings

Introduction: Using routine surveillance testing, a finding of very low safety significance (Green) was self-revealed. The finding has an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," for the failure to properly implement procedure LIS-NB-115B. Specifically, operations and maintenance personnel did not establish proper field communications while testing EFCVs and consequently operated the wrong component. As a result, a Division 2 ECCS signal was received and control room operators were subjected to an unnecessary operational distraction.

Description: On February 11, 2010, Unit 1 was in RFO L1R13. The plant was in the refueling mode of operation with the primary coolant temperature being maintained at 83 degrees Fahrenheit. Instrument Maintenance and Operations personnel were in the field performing LIS-NB-115B, "Unit 1 High Pressure Excess Flow Check Valve Operability Test." The purpose of this test is to verify operability of reactor instrument line high pressure EFCVs by isolating all of its associated downstream instrumentation and opening a single drain route. The operators in the control room then verify that the flow is stopped by the EFCV closure, using their board indications.

The field teams were supposed to test check valves 1B21-F361, 1B21-F372 and 1B21-F355, in that order. The personnel performing LIS-NB-115B were divided into three teams. The first team was stationed at the instrument racks where they would isolate the required instrument valves. A second team would be in charge of operating the EFCV root valves and test rig, and the third team would monitor EFCV indications in the control room. After successfully testing check valve 1B21-F361, the instrument rack team moved to 1B21-F372 testing location, but the valve team mistakenly moved to 1B21-F355. All three teams were required to establish communications with each other using head sets. However, due to the location of the head set plug and cord length, the valve team maintenance technician in communication with the other two teams was 25 feet away from the technician operating the EFCV root valve. Consequently, the technician operating the EFCV root valve did not receive the correct message as to the component number that was to be operated and, as a result, isolated the root valve for 1B21-F355.

Since the instrument valves for 1B21-F372 were the ones correctly isolated, when the root valve for 1B21-F355 was closed, an unexpected Division 2 ECCS signal was received in the control room. Normally, when this signal is received in the control room, the associated Division 2 ECCS systems and Emergency Diesel Generator (EDG) receive a start signal. The injection valves should open and the pumps would start to inject water to the reactor. However, as part of corrective actions implemented after a similar event occurred in Unit 2 during RFO L2R11 (NCV 05000373/2007002-05 where vessel nozzle flushing activities in the Unit 2 refuel floor caused an inadvertent initiation of the Division 1 ECCS), both Division 2 ECCS pumps (B and C low pressure coolant injection (LPCI) pumps) were in pull-to-lock. In addition, the Division 2 EDG was taken out-of-service at the time for planned outage maintenance. As a result, no water was injected into the reactor cavity. When the unexpected Division 2 ECCS signal was received, the injection valves for the B and C LPCI pumps opened and multiple alarm annunciators were received in the control room. This event constituted an unnecessary operational distraction for the operators.

<u>Analysis</u>: The inspectors concluded that the failure to properly implement procedure LIS-NB-115B by not maintaining direct communication between work locations and operating the wrong plant component that resulted in a Division 2 ECCS signal, constituted a performance deficiency that warranted evaluation using the SDP.
Using IMC 0612, Appendix B, “Issue Screening,” the inspectors determined that the finding was of more than minor significance because it affected the Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety function during shutdown as well as power operations. It also affected the Human Performance Cornerstone attribute due to the multiple errors associated field communications and procedure use and it affects the Configuration Control attribute for shutdown lineup. The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” and conducted a Phase 1 characterization and initial screening. Because this finding occurred during the refueling mode of operation, the inspectors used IMC 0609, Appendix G, “Shutdown Operations Significance Determination Process.”
Using Checklist 7, “Boiling Water Reactor Refueling Operation with Reactor Coolant System Level above 23 Feet,” of Appendix G, Attachment 1, “Phase 1 Operational Checklists for Both Pressurized Water Reactors and Boiling Water Reactors,”
the inspectors qualitatively determined that the finding involved adequate mitigation capability and was not an event that could be characterized as a loss of control. As a result, the inspectors concluded that the finding was of very low safety significance (Green).

The finding was also determined to have been related to the cross-cutting area of Human Performance, as defined in IMC 0305, “Operating Reactor Assessment Program.” Specifically, the finding was related to the Work Practices component because personnel did not appropriately follow procedure LIS-NB-115B, by not maintaining direct communication between work locations and as a result operating the wrong plant component. (H.4.b)

<u>Enforcement</u>: Criterion V of 10 CFR 50, Appendix B, “Instructions, Procedures, and Drawings,” states, in part, that: “Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.”

Contrary to this requirement, on February 11, 2010, licensee personnel conducting testing of Unit 1 EFCVs inappropriately implemented procedure LIS-NB-115B by not maintaining proper communications between work locations in the field and operating the wrong component. As a result, an unintentional signal to safety-related Division 2 ECCS equipment was received and control room operators were subjected to an unnecessary operational distraction. The licensee entered this issue into their CAP as IR 1029238. Corrective actions planned and completed by the licensee included halting all EFCV testing until an initial investigation into the event was performed and conducting an apparent cause evaluation for the event. Because the licensee has entered the issue into their CAP and the finding is of very low safety significance, this violation of 10 CFR 50, Appendix B, Criterion V, is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000373/2010002-02, Improper Procedure Implementation During Testing of Excess Flow Check Valve)

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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

- LES-PC-101 (Group 1 main steam isolation logic testing) (Routine);
- division II RTT (Routine);
- DG trip and trip bypass testing (Routine);
- 2A DG fast start (Routine);
- Unit 2 HPCS IST;
- MSIV local leak rate testing (LLRT) (ISO Valve);
- RHR and RCIC head injection valves LLRT (ISO Valve); and
- Unit 1 reactor coolant system hydrostatic testing (RCS leakage).

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency were in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;

- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for IST activities, testing was performed in accordance with the applicable version of Section XI, ASME code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted four routine surveillance testing samples, one IST sample, one reactor coolant system leak detection inspection samples, and two containment isolation valve samples as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2RS01 Radiological Hazard Assessment and Exposure Controls (71124.01)

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed all licensee performance indicators (PIs) for the Occupational Exposure Cornerstone for followup. The inspectors reviewed the results of radiation protection (RP) program audits (e.g., licensee’s quality assurance audits or other independent audits). The inspectors reviewed reports of operational occurrences related to occupational radiation safety since the last inspection. The inspectors reviewed the results of the audit and operational report reviews to gain insights into overall licensee performance.

b. Findings

No findings of significance were identified.

.2 Radiological Hazard Assessment (02.01)

a. Inspection Scope

The inspectors determined if there have been changes to plant operations since the last inspection that may result in a significant new radiological hazard for onsite workers or members of the public. The inspectors verified whether the licensee had assessed the potential impact of these changes and has implemented periodic monitoring, as appropriate, to detect and quantify the radiological hazard.

The inspectors reviewed the last two radiological surveys from three to six selected plant areas. The inspectors assessed whether the thoroughness and frequency of the surveys were appropriate for the given radiological hazard.

The inspectors conducted walkdowns of the facility, including radioactive waste processing, storage, and handling areas to evaluate material conditions and performed independent radiation measurements to verify conditions.

The inspectors selected the following radiologically risk-significant work activities that involved exposure to radiation.

- drywell ISI;
- under-vessel instrumentation;
- control rod drive pull/put; and
- recirculation pump and motor repair.

For these work activities, the inspectors assessed whether the pre-work surveys performed were appropriate to identify and quantify the radiological hazard and to establish adequate protective measures. The inspectors evaluated the radiological survey program to determine if hazards were properly identified, including the following:

- identification of hot particles;
- the presence of alpha emitters;
- the potential for airborne radioactive materials, including the potential presence of transuranics and/or other hard-to-detect radioactive materials, (may include licensee planned entry into non-routinely entered areas subject to previous contamination from failed fuel);
- the hazards associated with work activities that could suddenly and severely increase radiological conditions and that the licensee has established a means to inform workers of changes that could significantly impact their occupational dose; and
- severe radiation field dose gradients that can result in non-uniform exposures of the body.

The inspectors selected three air sample survey records and verified whether samples were collected and counted in accordance with licensee procedures.

The inspectors observed work in potential airborne areas to verify that air samples were representative of the breathing air zone. The inspectors evaluated whether continuous air monitors were located in areas with low background to minimize false alarms and were representative of actual work areas. The inspectors reviewed records to determine if the licensee had a program for monitoring levels of loose surface contamination in areas of the plant with the potential for the contamination to become airborne.

b. Findings

No findings of significance were identified.

.3 Instructions to Workers (02.03)

a. Inspection Scope

The inspectors reviewed the following radiation work permits (RWPs) used to access high radiation areas (HRAs) and evaluated the specified work control instructions or control barriers.

- drywell ISI;
- under-vessel instrumentation;
- control rod drive pull/put and;
- recirculation pump and motor repair; and
- drywell safety relief valve activities.

For these RWPs, the inspectors verified whether the allowable stay times or permissible dose (including from the intake of radioactive material) for radiologically significant work under each RWP was clearly identified. The inspectors verified whether the electronic personal dosimeter alarm setpoints were in conformance with survey indications and plant policy.

b. Findings

No findings of significance were identified.

.4 Contamination and Radioactive Material Control (02.04)

a. Inspection Scope

The inspectors observed locations where the licensee monitors potentially contaminated material leaving the radiologically controlled area, and evaluated the methods used for control, survey, and release from these areas. The inspectors observed the performance of personnel surveying and releasing material for unrestricted use to verify that the work was performed in accordance with plant procedures. The inspectors also reviewed whether the procedures were sufficient to control the spread of contamination and prevent unintended release of radioactive materials from the site. The inspectors determined if the radiation monitoring instrumentation had appropriate sensitivity for the types of radiation present.

b. Findings

No findings of significance were identified.

.5 Radiological Hazards Control and Work Coverage (02.05)

a. Inspection Scope

The inspectors evaluated ambient radiological conditions (e.g., radiation levels or potential radiation levels) during tours of the facility. The inspectors verified whether the conditions were consistent with applicable posted surveys, RWPs, and worker briefings.

The inspectors assessed the adequacy of radiological controls, such as required surveys (including system breach radiation, contamination, and airborne surveys), RP job coverage (including audio and visual surveillance for remote job coverage), and contamination controls. The inspectors evaluated the licensee's use of electronic personal dosimeters in high noise areas as HRA monitoring devices.

The inspectors verified whether radiation monitoring devices were placed on the individual's body consistent with licensee procedures. The inspectors evaluated whether the dosimeter was placed in the location of highest expected dose or that the licensee had properly employed an NRC-approved method of determining effective dose equivalent.

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

The inspectors reviewed the following RWPs for work within airborne radioactivity areas with the potential for individual worker internal exposures.

- turbine shroud repair; and
- reactor water clean-up check valve.

For these RWPs, the inspectors evaluated airborne radioactive controls and monitoring, including potentials for significant airborne levels (e.g., grinding, grit blasting, system breaches, entry into tanks, cubicles, reactor cavities). The inspectors evaluated barrier (e.g., tent or glove box) integrity and temporary high-efficiency particulate air (HEPA) ventilation system operation for selected airborne radioactive material areas.

The inspectors inspected the posting and physical controls for selected HRAs and very high radiation areas (VHRAs), to verify conformance with the Occupational PI. There were no VHRAs to observe controls.

b. Findings

No findings of significance were identified.

.6 Radiation Worker Performance (02.07)

a. Inspection Scope

The inspectors observed radiation worker performance with respect to stated RP work requirements. The inspectors assessed whether workers were aware of the significant radiological conditions in their workplace and the RWP controls/limits in place and that their performance reflects the level of radiological hazards present.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency (02.08)

a. Inspection Scope

The inspectors observed the performance of the RP technician with respect to all RP work requirements. The inspectors evaluated whether technicians were aware of the radiological conditions in their workplace and the RWP controls/limits and whether their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

b. Findings

No findings of significance were identified.

.8 Problem Identification and Resolution (02.09)

This inspection constituted a partial sample as defined in IP 71124.01-5.

a. Inspection Scope

The inspectors assessed whether problems associated with radiation monitoring and exposure control were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee CAP. The inspectors evaluated the appropriateness of the corrective actions for a selected sample of problems documented by the licensee that involve radiation monitoring and exposure controls. The inspectors assessed the licensee's process for applying operating experience to their plant.

b. Findings

No findings of significance were identified.

2RS02 Occupational ALARA Planning and Controls (71124.02)

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed pertinent information regarding plant collective exposure history, current exposure trends, and ongoing or planned activities in order to assess current performance and exposure challenges. The inspectors reviewed the plant's 3-year rolling average collective exposure.

The inspectors reviewed the site-specific trends in collective exposures (using NUREG-0713, "Occupational Radiation Exposure at Commercial Nuclear Power Reactors and Other Facilities," and plant historical data) and source term (average contact dose rate with reactor coolant piping) measurements (using Electric Power Research Institute TR-108737, "BWR Iron Control Monitoring Interim Report," issued December 1998, and/or plant historical data, when available).

The inspectors reviewed site-specific procedures associated with maintaining occupational exposures as-low-as-is-reasonably-achievable (ALARA), which included a review of processes used to estimate and track exposures from specific work activities.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning (02.02)

a. Inspection Scope

The inspectors selected five work activities of the highest exposure significance with greater than 5 person-rem of exposure. The inspectors determined whether the licensee reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances. The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements.

The inspectors assessed whether the licensee's planning identified appropriate dose mitigation features; considered alternate mitigation features; and defined reasonable dose goals. The inspectors evaluated the licensee's ALARA assessment had taken into account decreased worker efficiency from use of respiratory protective devices and/or heat stress mitigation equipment (e.g., ice vests). The inspectors determined whether the licensee's work planning considered the use of remote technologies (e.g., teledosimetry, remote visual monitoring, and robotics) as a means to reduce dose and the use of dose reduction insights from industry operating experience and plant-specific lessons learned. The inspectors assessed the integration of ALARA requirements into work procedure and RWP documents.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the assumptions and basis (including dose rate and man-hour estimates) for the current annual collective exposure estimate for reasonable accuracy for select ALARA work packages. The inspectors reviewed applicable procedures to determine the methodology for estimating exposures from specific work activities and the intended dose outcome.

The inspectors evaluated whether the licensee had established measures to track, trend, and, if necessary, to reduce, occupational doses for ongoing work activities. The inspectors assessed whether trigger points or criteria were established to prompt additional reviews and/or additional ALARA planning and controls.

The inspectors evaluated the licensee's method of adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered. The inspectors assessed whether adjustments to exposure estimates (intended dose) were based on sound RP and ALARA principles or if they are just adjusted to account for failures to control the work. The inspectors evaluated whether the frequency of these adjustments called into question the adequacy of the original ALARA planning process.

b. Findings

No findings of significance were identified.

.4 Source Term Reduction and Control (02.04)

a. Inspection Scope

The inspectors used licensee records to determine the historical trends and current status of significant tracked plant source terms known to contribute to elevated facility aggregate exposure. The inspectors assessed whether the licensee had made allowances or developed contingency plans for expected changes in the source term as the result of changes in plant fuel performance issues or changes in plant primary chemistry.

b. Findings

No findings of significance were identified.

.5 Radiation Worker Performance (02.05)

This inspection constituted a partial sample as defined in IP 71124.02-5.

a. Inspection Scope

The inspectors observed radiation worker and RP technician performance during work activities being performed in radiation areas, airborne radioactivity areas, or HRAs. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice (e.g., workers are familiar with the work activity scope and tools to be used, workers used ALARA low-dose waiting areas) and whether there were any procedure compliance issues (e.g., workers are not complying with work activity controls). The inspectors observed radiation worker performance to assess whether the training and skill level was sufficient with respect to the radiological hazards and the work involved.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator (PI) Verification (71151)

.1 Unplanned Scrams per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the unplanned scrams per 7000 critical hours PI, Units 1 and 2, for the period from the 1st quarter 2009 through the 4th quarter 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports and NRC inspection reports for the period of January 2009 through December 2009, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings of significance were identified.

.2 Unplanned Scrams with Complications

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams with Complications PI, Units 1 and 2, for the period from the 1st quarter 2009 through the 4th quarter 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports and NRC integrated inspection reports for the period of January 2009 through

December 2009, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings of significance were identified.

.3 Unplanned Transients per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the unplanned transients per 7000 critical hours PI, Units 1 and 2, for the period from the 1st quarter 2009 through the 4th quarter 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, maintenance rule records, event reports and NRC integrated inspection reports for the period of January 2009 through December 2009, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

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

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

a. Inspection Scope

As part of the various baseline IPs discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: the complete and accurate identification of the problem; that timeliness was commensurate with the safety significance; that evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the attached List of Documents Reviewed.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure, they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings of significance were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

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

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

b. Findings

No findings of significance were identified.

.3 Selected Issue Followup Inspection: L1R13 Refueling Outage Startup Issues

a. Inspection Scope

The inspectors reviewed the items identified during the L1R13 RFO which were coded into the licensee's CAP as a L1R13 reactor startup hold as well as those items deferred to future outages for repair. The inspectors ensured that the licensee prioritized and completed repairs for safety significant and risk-significant components and systems. The inspectors reviewed repair records and walked down components and systems identified as failed during the outage. The inspectors also attended licensee pre-startup Plant Oversight Review Committee meetings to observe the site senior management decision making and vetting process. The inspectors challenged the licensee's decision to enter Mode 4 (cold shutdown) from Mode 5 (refueling) with a degraded shutdown cooling train B as the 1D RHR SW pump was being emergently replaced. The licensee complied with all TI requirements and identified and maintained adequate alternate shutdown cooling sources during this degraded time period.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152-05.

b. Findings

No findings of significance were identified.

4OA5 Other Activities

.1 (Open) NRC TI 2515/177, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems (NRC Generic Letter 2008-01)"

a. Inspection Scope and Documentation

On February 18, 2009, the inspectors conducted a walkdown of normally inaccessible portion of piping of the Unit 1 low pressure core spray system (LPCS) and the HPCS system in sufficient detail to reasonably assure the acceptability of the licensee's walkdowns (TI 2515/177, Section 04.02.d).

In addition, the inspectors verified that the licensee had isometric drawings that describe the Unit 1 HPCS and LPCS system configurations and had acceptably confirmed the accuracy of the drawings (TI 2515/177, Section 04.02.a). The inspectors verified the following related to the isometric drawings:

- high point vents were identified;
- high points that do not have vents were acceptably recognizable;
- other areas where gas can accumulate and potentially impact subject system operability, such as at orifices in horizontal pipes, isolated branch lines, heat exchangers, improperly sloped piping, and under closed valves, were acceptably described in the drawings or in referenced documentation;
- horizontal pipe centerline elevation deviations and pipe slopes in nominally horizontal lines that exceed specified criteria were identified;
- all pipes and fittings were clearly shown; and
- the drawings were up-to-date with respect to recent hardware changes and that any discrepancies between as-built configurations and the drawings were documented and entered into the CAP for resolution.

The inspectors verified that piping and instrumentation diagrams (P&IDs) accurately described the subject systems, that they were up-to-date with respect to recent hardware changes, and any discrepancies between as-built configurations, the isometric drawings, and the P&IDs were documented and entered into the CAP for resolution (TI 2515/177, Section 04.02.b).

Documents reviewed are listed in the Attachment to this report.

In addition, as documented in Sections 1R04, 1R18, and 1R20, the inspectors confirmed the acceptability of the described licensee's actions. This inspection effort counts towards the completion of TI 2515/177 which will be closed on a future inspection report.

4OA6 Management Meetings

.1 Exit Meeting Summary

On April 14, 2010, the inspectors presented the inspection results to Mr. Dave Wozniak, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- the results of the ISI with Site Vice President, Mr. Dave Wozniak, and other members of the licensee's staff on February 17, 2010; and
- the results of the Radiological Hazard Assessment and Exposure Controls and ALARA Controls inspection with the Site Vice President, Mr. Dave Wozniak, and other members of the licensee's staff on February 22, 2010.

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

4OA7 Licensee-Identified Violations

None.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

D. Wozniak, Site Vice President
D. Rhoades, Plant Manager
K. Aleshire, Exelon EP Programs Manager
D. Amezaga, GL 89-13 Program Owner
D. Anthony, Exelon NDE Manager West
J. Bashor, Site Engineering Director
L. Blunk, Operations Training Manager
D. Carpenter, Senior ISFSI Project Manager
H. Do, Corporate ISI Manager
P. Endress, Design Engineer
M. Entwistle, Operation Training
J.C. Feeney, NOS Lead Assessor
F. Gogliotti, System Engineering Senior Manager
D. Henly, Design Engineer
W. Hilton, Engineering Supervisor – Mechanical/Structural
J. Houston, Regulatory Assurance
J. Hughes, Emergency Preparedness Coordinator
K. Ihnen, Nuclear Oversight Manager
A. Kochis, ISI Engineer
R. Leasure, Radiation Protection Manager
B. Maze, ISFSI Project Manager
J. Meyer, Exelon Nuclear Oversight Inspector
J. Miller, NDE Level III
J. Paczolt, Operation Training
B. Rash, Maintenance Director
J. Rommel, Design Engineering Senior Manager
K. Rusley, Emergency Preparedness Manager
J. Shields, ISI Program Supervisor
S. Shields, Regulatory Assurance
T. Simpkin, Regulatory Assurance Manager
K. Taber, Operations Director
W. Trafton, Shift Operations Superintendent
J. Vegara, Regulatory Assurance
H. Vinyard, Work Management Director
J. White, Site Training Director
G. Wilhelmsen, Design Manager
S. Wilkinson, Chemistry Manager
C. Wilson, Station Security Manager

Nuclear Regulatory Commission

K. Riemer, Chief, Reactor Projects Branch 2
B. Dickson, Branch Chief, Plant Support Team, DRS/RIII

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000373/2010002-01; 05000374/2010002-01	NCV	Failure to Maintain Design Control of SBLC system (1R12)
000373/2010002-02	NCV	Improper Procedure Implementation During Testing of Excess Flow Check Valve (1R20)
TI 2515/177	TI	Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems (NRC Generic Letter 2008-01) (4OA5)

Closed

05000373/2010002-01; 05000374/2010002-01	NCV	Failure to Maintain Design Control of SBLC system (1R12)
05000373/2010002-02	NCV	Improper Procedure Implementation During Testing of Excess Flow Check Valve (1R20)

LIST OF DOCUMENTS REVIEWED

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

1R04 Equipment Alignment (71111.04)

Issue Reports:
- 1015444; UT Finds Small Void Upstream of 1E12-F016B After LOS-RX-SR1; 1/12/2010
- 1018454; NRC Identified Issue – Leak from 1E12-R529; 1/19/2010
- 1018455; NRC Identified Issue – Cart Blocking Stairs; 1/19/2010
- 1026176; NRC Identified: Housekeeping Issue U1 RB; 2/4/2010

Drawings:
- ISI-LP-1001; In-service Inspection Isometric Low Pressure Core Spray System; Rev. A
- ISI-LP-1002; In-service Inspection Isometric Low Pressure Core Spray System; Rev. A
- ISI-LP-1003; In-service Inspection Isometric Low Pressure Core Spray System; Rev. A
- ISI-LP-1013; In-service Inspection Isometric Low Pressure Core Spray System; Rev. A
- ISI-LP-1014; In-service Inspection Isometric Low Pressure Core Spray System; Rev. A
- ISI-RH-1001; In-service Inspection Isometric RHR System Piping System; Rev. A
- ISI-RH-1002; In-service Inspection Isometric Residual Heat Removal System; Rev. A
- ISI-RH-1006; In-service Inspection Isometric Residual Heat Removal System; Rev. A
- ISI-RH-1007; In-service Inspection Isometric Residual Heat Removal System Southeast Loop; ISI-RH-1008; In-service Inspection Isometric Residual Heat Removal System; Rev. A
- ISI-RH-1009; In-service Inspection Isometric Residual Heat Removal System; Rev. A
- ISI-RH-1011; In-service Inspection Isometric Residual Heat Removal System; Rev. A
- ISI-RH-1031; In-service Inspection Isometric Residual Heat Removal System; Rev. A
- ISI-RH-1036; In-service Inspection Isometric Residual Heat Removal System; Rev. A
- ISI-RH-1046; In-service Inspection Isometric Residual Heat Removal System; Rev. A
- ISI-RH-1047; In-service Inspection Isometric RHR System; Rev. A
- ISI-RH-1077; In-service Inspection Isometric Residual Heat Removal System; Rev. A
- M-837; Low Pressure Core Spray Piping; Rev. AJ

Working Documents:
- LOP-RH-01E; Unit 1 RHR Service Water System Electrical Checklist; Rev. 8
- LOP-RI-02E; Unit 2 Reactor Core Isolation Cooling System Electrical Checklist; Rev. 14
- LOP-RI-02M; Unit 2 Reactor Core Isolation Cooling System Mechanical Checklist; Rev. 19
- LOP-RHWS-1BM; Unit 1 B RHR Service Water System Mechanical Checklist; Rev. 4

1R05 Fire Protection (71111.05)

Procedures:
- OP-AA-201-009; Control of Transient Combustible Material; Rev. 9

Working Documents:
- UFSAR; Updated Final Safety Analysis Report, Fire Protection System, Elevation 731’-0”, 710’ and 740’; Rev. 3

Miscellaneous:
- LSCS-FPR, Fire Protection Report for Fire Zone 5B4; Rev. 3
- LSCS-FPR, Fire Protection Report for Fire Zone 2G; Rev. 3
- LSCS-FPR, Fire Protection Report for Fire Zone 2F; Rev. 3
- LSCS-FPR, Fire Protection Report for Fire Zone 3F; Rev. 3
-
- 1R07 Annual Heat Sink Performance (71111.07)

Procedures:
- LTS-200-17; RHR Heat Exchanger Thermal Performance Monitoring; Rev. 10

Drawings:
- ISI-HP-1001; In-service Inspection Isometric High Pressure Core Spray Southeast Loop; Rev. A
- ISI-HP-1002; In-service Inspection Isometric High Pressure Core Spray System; Rev. A
- ISI-HP-1003; In-service Inspection Isometric High Pressure Core Spray System; Rev. A
- ISI-HP-1004; In-service Inspection Isometric High Pressure Core Spray System; Rev. A
- ISI-HP-1005; In-service Inspection Isometric High Pressure Core Spray System; Rev. A
- ISI-HP-1007; In-service Inspection Isometric High Pressure Core Spray Piping System; Rev. A

Working Documents:
- EC 378754; 1A RHR Heat Exchanger Thermal Performance Test Data Evaluation; 2/12/2010

1R08 In-service Inspection Activities (71111.08)

Procedures:
- 1-1-GTSM-PWHT ; Weld Procedure Specification; Rev. 1
- 1-8-GTSM; Weld Procedure Specification; Rev. 1
- ER-AA-335-016, VT-3 Visual Examination of Component Supports, Attachments and Interiors of Reactor Vessels; Rev. 5
- GE-PDI-UT-1; PDI Generic Procedure for the Ultrasonic Examination of Ferritic Pipe Welds; Rev. 6
- GE-PDI-UT-2; PDI Generic Procedure for the Ultrasonic Examination of Austenitic Pipe Welds; Rev. 4
- GEH-VT-205; Procedure for Invessel Visual Inspection (IVVI) of BWR 5 RPV Internals; Rev. 11
- GEH-UT-247; Procedure for Phased Array Ultrasonic Examination of Dissimilar Metal Welds; Rev. 2
- GEH-UT-311; Procedure for Manual Examination of Nozzle Inner Radius, Bore and Selected Nozzle to Vessel Regions, Rev. 16.
- Qualification Record; A-001; 10/19/1998
- Qualification Record; A-002; 3/9/1999
- Qualification Record; 1-50C; 1/3/1994
- Qualification Record; 1-53B; 1/29/1986
- Qualification Record; 2-53A; 2/12/1986
- Qualification Record; 002-41-055; 2/3/1994

Issue Reports:
- 738522; Spherical Bearing Protruding on MS00-1052S; 2/20/2008
- 740081; CRD Flange Leakage Noted; 3/14/2007
- 747893; Results of UT of Core Spray Piping Inside UT Rx; 3/11/2008

- 865730; ISI Welds not Examined; 1/12/2009
- 874726; Pipe Wall Issues; February 1, 2009
- 876860; CRD Flange Leakage Identified; 2/5/2009
- 876868; CRD Flange Leakage Identified; 2/23/2008
- 876876; CRD Flange Leakage Identified; 2/23/2008
- 894049; DM Weld Ultrasonic Inspections; 3/17/2009
- 894974; LPCS Flaw Inside Reactor; 3/19/2009
- 919166; Licensee Identified Violation; 3/31/2009
- 921077; OE Applicable to LaSalle, Weld Exams by GEH; 5/18/2009
- 1030879; Relevant ISI Indications on RV Head Washers; 2/16/2010
- 1031448; Action to Minimize CRDM Flange Leakage not in CAP; 2/16/2010

Drawings:
- 232-923; Stud, Nut and Washer Details; Rev. 2

Miscellaneous:
- ASME Form NPV-1:150 No. Feedwater Gate Valve Body; 10/15/2007
- ASME Repair/Replacement Plan; Valve 1E12-F330C; 1/29/2010
- ASME Repair/Replacement Plan; Valve 1E12-F330D; 1/29/2010
- Certified Material Test Report; Wire Heat No 735032; 1/5/2009
- Certified Material Test Report; Wire Heat No CM8411; 1/5/2009
- GE Report No. DRF 0000-0112-1863; Reactor Pressure Vessel Washer Indications LaSalle 1, 2/2010
- NDE Report No L1R-12-002; RPV Head-to-Flange Weld GE:-1009-AG-MT; 2/14/2008
- NDE Report No L1R-12-029, RPV Washers Coating Loss; 2/10/2008
- NDE Report No E10-041; MS00-1011S; 2/10/2010
- NDE Report No 10-102; 1E12-F330C, FW-1; 2/14/2020
- NDE Report No L1R13-APR-007; LP-1001-33B Safe End Ext to Safe End; 2/16/2010
- NDE Report No L1R13-011, LCS-1-N6A; Nozzle to Shell; 2/17/2010
- Welder Performance Qualification; D7214; 10/12/2009
- Welder Performance Qualification; S0456; 8/22/2006
- 1R11 Licensed Operator Requalification Program (71111.11)

Miscellaneous:
- Simulator training scenario 1st quarter 2010

1R12 Maintenance Effectiveness (71111.12)

Procedures:
- LMP-GM-06; Bench Testing/Setting of ASME OM Class 2 and 3 Safety Relief Valves; Rev. 27

Issue Reports:
- 521122; Unusual Flow Noise During LOS-SC-Q1 with 1B SBLC Pump; 8/17/2006
- 600763; 2A SBLC Pump Flow Low in Acceptance Range; 3/8/2007
- 601236; 2B SBLC Pump Flow Low in Acceptance Range; 3/8/2007
- 980756; 2C41-F029A Lifted During LOS-SC-Q1; 10/17/2009
- 981392; 2C41-F029A Blown Bellows; 10/19/2009
- 1000566; SC Relief Valve Failures; 12/2/2009
- 1001151; Relief Valve Failed As-Found Test Following Replacement; 12/3/2009
- 1014305; Relief Valve Failed As-Found Set-Pressure Test; 1/8/2010
- 1017015; Thermography Identifies New Hotspot on U2 MPT-SY Disconnect; 1/15/2010

- 1019471; Summary of Recent SBLC Relief Valve Issues; 1/21/2010
- 1021467; Emergent Grid Block Issues in LaSalle Switchyard; 1/26/2010
- 1021472; Emergent Issues with OCB's in the Switchyard; 1/26/2010
- 1022445; NRC Request for ATWS Documents; 1/28/2010
- 1027108; Thermography Id's Hotspot on BT 9-10 Bus 9 Disc. B Phase
- 1032792; Stationary Contact Block Found Broken; 2/19/2010

Working Documents:
- AR 1001151-03; Complete CDE for IR 1001151; 1/15/2010
- AR 980756-05; Perform Equipment Apparent Cause Evaluation (EACE); 11/24/2009
- NFM-MW:01-0374; ATWS Kinetics Parameters for LaSalle: Acceptance of ATRIUM-ID Fuel ATWS Performance for LaSalle; Rev. 0
- WO 1113706; Work Order Completion Status for EM SSC to Perform PM Inspection and Clean the SAT Transform; 2/22/2010
- WO 1113704;Work Order Completion Status for XFMR Conduit, Cabinet, Junc box Water Tightness and Wiring Ins; 2/21/2010
- WO 1113708; Work Order Completion Status for MA-LA-773-231, SAT 142 Panels 1PA02J/18J; 2/21/2010
- WO 1248324; Work Order Completion Status for Replace U1 SAT HV Bushings in L1R13; 2/21/2010
- WO 01280231-01; MM To Replace 1C41-F029A (SBLC) Pump Discharge Relief VLV (Task Completion); 12/1/2009
- WO 1311839; Work Order Completion Status for Unit 1 SAT Trip; 3/7/2010
- WO 1146404-02; MM Set Point Test Spare Valve that was Removed and Replaced (Task Completion); 1/15/2010
- WO 1217099; Work Order Completion Status for Perform PF/CAP Test on U1 Sat; 3/5/2010
- WO 1280232-02; MM to Set 2C41-F029A (SBLC) Pump Discharge relief VLV per EC (Task Completion); 12/16/2009
- WO 1280233-02; MM to Set 1C41-F029B (SBLC) Pump Discharge Relief VLV per EC (Task Completion); 12/1/2009
- WO 1280233-08; Safety and Relief Valve Test Data Sheet for 2C41-F029A;
- WO 1280236-08; Safety and Relief Valve Test Data Sheet for 2C41-F029B; 12/3/2009
- WR 960055481-01; Safety and Relief Valve Test Data Sheet for 2C41-F029A; 4/28/1998
- WR 960055485-01; Safety and Relief Valve Test Data Sheet for 2C41-F029A; 4/25/1998
- WR 980098695-01; Safety and Relief Valve Test Data Sheet for 2C41-F029A; 3/26/1999
- WR 990025950-01; Safety and Relief Valve Test Data Sheet for 2C41-F029A; 10/14/1999
- WR 99002595-01; Safety and Relief Valve Test Data Sheet for 2C41-F029A; 10/9/2000
- WR 990027950-01; Safety and Relief Valve Test Data Sheet for 2C41-F029A; 11/12/2000

Miscellaneous:
- Currently Installed Relief Valves, Series N60735
- CY-04/CY-05; Risk Significance Revision, Cycled Condensate; 1/22/2010
- LSCS-UFSAR; Anticipated Transients without SCRAM (ATWS); Rev. 13
- Maintenance Rule Performance Criteria for Switchyard; 3/2008 – 3/2010
- Maintenance Rule Scoping, Risk Significance Summary for SC; 1/21/2010
- ROP PIM Report, 2000 – 2010; 2/4/2010
- Relief Valve N60735-00 Series Set-Pressure Test Results; 1998 – 2010
- Safety Evaluation by the Office of Nuclear Reactor Regulation Relating to the Implementation of the ATWS Rule

- SC-01, SC-04; SC Evaluation of Functional Failures and Reliability Criteria for 1/2008 - 12/2009
- Quad-1-83-007; Analysis Report: Alternated Rod Insertion System for LaSalle County Station - Unit 2; 4/12/1983

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

Procedures:
- ER-AA-600-1014; Risk Management Configuration Control Training and Reference Material; Rev. 5
- OP-AA-106-101; Notification Requirements; Rev. 13
- WC-AA-104; Integrated Risk Management; Rev. 15

Issue Reports:
- 1033501; Unit 1 SAT Trip; 2/21/2010
- 1033503; Unit 1 SAT Trip; 2/21/2010
- 1034593; EN-AA-103-0003, Att. 2 – U1 SAT Draining; 2/23/2010
- 1035518; U-1 SAT 142 B-Phase Bushing Turret Not Oriented Correctly; 2/25/2010
- 1041521; 1B DG Fuel Line Leak; 3/11/2010

Work Documents:
- L1R13:Log 33; Movement Div 1 RTT, 1A DG T & Trip Bypass Testing; 2/22/2010
- L1R13:Log 34; Shutdown Safety Approval for Draindown without SRV's, Movement of Line 0104 and A SRM Repair; 2/23/2010
- WO 1248324-01; Replace U1 SAT HV Bushings in L1R13; 11/19/2009

Drawings and Graphs:
- Fig 42-14; 345 kv Switchyard Components; 9/27/1990

Miscellaneous:
- ABB Inc. LaSalle Unit 1 Station Auxiliary Transformer 142 Repair Checklist; 2/23/2010
- ER-AA-600; Requirements and Responsibility of the Exelon Risk Management Program; Rev. 5
- IR 1033503/1033501; Equipment Prompt Investigation Report for Unit 1 System Auxiliary Transformer Tripped (SAT); 2/21/10
- L1R13 PORC; System Auxiliary Transformer (SAT) (IR 103353)
- L1R13 PORC; Shutdown Safety Management Program – PORC Approval Document; 1/26/2010
- SAT Window/Activities for L1R13; 2/24/2010
- T&RM: Training and Reference Material for General Approach to Exelon Nuclear Project Risk Management; Rev. 1
- T&RM; Training & Risk Management: Guidance for Risk Management Support of the Shutdown Safety Management Program

1R15 Operability Evaluations (71111.15)

Procedures:
- ER-AA-321; Administrative Requirements for In-service Testing; Rev. 10
- LOS-AA-S101; Unit 1 Shiftly Surveillance; Rev. 62
- LOS-DG-Q3; 1B(2B) Diesel Generator Auxiliaries In-service Test; Rev. 54
- LTS-600-8; Reactor Vessel Internals In-service Inspection During Reactor Refueling; Rev. 18

Issue Reports:
- 483096; No Significant JP Wear in L1R11; 4/25/2006
- 984453; Standby Liquid Control System Performance; 10/26/2009
- 1014305; Relief Valve Failed As-Found Set-Pressure Test; 1/8/2010
- 1024922; Non-Conforming HCU Directional Control Valve Fasteners; 2/2/2010
- 1026306; HPCS DGCWP DP Outside Biennial Acceptable Range; 2/5/2010
- 1031936; 1A DG Voltage response During LOS-DG-110; 2/17/2010

Work Documents:
- AR 598883-21; Evaluate Defeating the Auto Initiation of Safety Injection and Diesel Generator Start; 5/31/2007
- AR 598883-23; Implement ECCS Auto-Injection Configuration Control Method prior to L1R12; 12/31/2007
- AR 723985-29; Add restriction to LTS-600-8 in EC 378202 to remove 100% core flow restriction from U1; 5/28/2010
- DCP 9400115; Design Change Package: SBLC Pump Discharge Relief Valve Setpoint; 7/21/1994
- DCP 9900359; Jet Pump Slip Joint Bypass Flow Clamp Repair: Contingency: 9/2000
- EC 378202; Lifting the 100% Unit 1 Jet Pump Core Flow Restriction; 12/30/2009
- EC 378747; Evaluation of Non-Conforming HCU Directional Control Valve Fasteners; Rev. 0
- LOS-DG-Q3; 1B DG Cooling Water Pump In-service Test Checklist; 9/3/2009
- LOS-DG-Q3; LaSalle IST Surveillance Acceptance Criteria Manual Approval Checklist; Rev. 7
- LOS-DG-Q3; LaSalle IST Surveillance Acceptance Criteria Manual Biennial Comprehensive Test Approval Checklist; Rev. 0
- LOS-DG-Q3; LaSalle IST Surveillance Acceptance Criteria Manual Pump Approval Checklist; Rev. 7
- WO 1270857-01; LOS-DG-Q1 0 DG Cooling Water Pump In-service Test; 12/22/2009
- WO 1285043-01; LOS-DG-Q3, 1B D/G Cooling Water Pump Inservice Test, Att A5; 2/2/10
- WO 128043; Work Order Completion Data; LOS-DG-Q3, 1B D/G Cooling Water Pump Inserv Test, Att. A5; 2/9/2010
- WO 1258887-01; LOS-DG-Q3, 1B D/G Cooling Water Pump Inserv Test, Att. A5; 11/6/2009

Drawings:
- LGA-010; Emergency Operating Procedure: Failure to Scram; 4/15/2009
- J-2944; RHR Service Water Pumps 1A, 1B
- M-87; P&ID Core Standby Cooling System Equipment Cooling Water System; Rev. AD
- M-99; P & ID Standby Liquid Control System; Rev. AA
- 1E-1-4000QB; Relaying & Metering Diagram Standby Diesel Generator “1A”; Rev. T

Calculations:
- 032130(EMD); Seismic Qualification of Control Rod Drive Hydraulic Control Units (CRD-HCU) TAG # C11-D001; 8/10/1981
- eDRF: 0000-0110-7896; GE Hitachi Nuclear Energy Engineering Calculation Sheet: Fatigue Usage Factor of Jet Pumps due to SJLFI and System Loads; 12/9/2009

Miscellaneous:
- Amendment No. 147/133; RHR Shutdown Cooling System – Cold Shutdown 3.4.10;
- SBLC Simplified Drawing (Training Document)
- SRV Discharge Locations and Relief/Safety Setpoints (Training Document)
- LSCS-UFSAR; SLC System 9.3 12-15; Revs. 13, 14, 18
- 028; Exelon Standby Liquid Control Training

- Pump EPN 0DG01P; Flow Test Data; 3/2006 - 12/2009
- ASME Code-2001; In-service Test Subsection (ISTB)
- NER NC-07-025 (draft); Yellow Nuclear Event Report CDBI Pump In-service Test (IST) Performance Issues; May 11, 2007
- GE Reactor Internals Projects Asset Management Plan JP-9, JP-10 Overview Diagram
- INR L1R10-04-05; GE Nuclear Energy: LaSalle Unit 1 Jet Pump Wedge Wear Indication Notification Report; 1/21/2004
- DCP 9900359; Design Attribute Review for NB, B13; Damage on Inlet Mixer Wedge During L1R06 & L1R07; Rev. 0
- GENE-B13-02076-00-01/ DRF B13-02076-00; GE Nuclear Energy: Slip Joint Clamp; Rev. 0
- AT 197310-20; Root Cause Report Unexpected Wear in Unit 1 Jet Pumps; 2/11/2004
- ASME OM CODE-2001; Subsection ISTB In-service Testing of Pumps in Light-Water Reactor Nuclear Power Plants; 4/2006
- 1E22-R003; Component Parameter Report
- 1E22-R537; Component Parameter Report
- Exelon LaSalle Plan of the Day Tuesday, February 21, 2010
- LSCS-UFSAR 8.3; Unit Reactor Protection System (RPS) Power System; Rev. 14
- Emergency Diesel Generators Training Documentation – Emergency Diesel Auto Starts

1R18 Plant Modifications (71111.18)

Drawings:
- IT-7000-M-PP-16; Generic CSCS Valve Replacement Details; Rev. A

Miscellaneous:
- EC 343542; Alternate Design for CSCS Valves (IT 7000 Drawing Created); 2/11/2010

1R19 Post-Maintenance Testing (71111.19)

Procedures:
- LOS-DG-102; Unit 1 1A Diesel Generator, 1DG01K, Start and Load Acceptance Surveillance; Rev. 4
- LES-RR-03; Reactor Recirculation Low Frequency Motor/Generator Set Preventative Maintenance Inspection; Rev. 9
- LOS-SC-Q1; SBLC Pump Operability/In-service Test and Explosive Valve Continuity Check; Rev. 29
- LOS-RH-Q1; RHR (LPCI) and RHR Service Water Pump and Valve In-service Test for Modes 1,2,3,4 and 5; Rev. 73

Issue Reports:
- 980756; 2C41-F029A Lifted During LOS-SC-Q1; 10/17/2009
- 1000566; SC Relief Valve Failures; 12/2/2009
- 1001151; Relief Valve Failed As-Found Test Following Replacement; 12/3/2009
- 1031860; L1R13 Critical Path Delay: RR Pump Interference Removal; 2/17/2010
- 1032098; 1E12-C300D Pump Hold Down Bolt Sheered Off; 2/18/2010
- 1033001; Need Vibes on 1E12-C300D Motor; 2/19/2010
- 1034185; 1B RR Pump Vibe Probe Mounting Holes Need Adjustment; 2/23/2010
- 1035278; 1B RR Motor Shaft to Ground Low Resistance Issue Disposition; 2/25/2010
- 1036324; Problems Identified when Performing LOS-RH-Q1; 2/27/2010
- 1036522; U-1 SAT “C” Phase Bushing Needs to be Re-Oriented; 2/28/2010

Drawings:
- 1E-1-4206AQ; Schematic Diagram RCMS, System RD Panel 1H13-P659: RCMS Power Module; Rev. C
- 1E-1-4207AE; Schematic Diagram Control Rod Drive Hydraulic System “RD” (C118) Part 5; Rev. F
- 1E-1-4206CF; Schematic Diagram RCMS, System “RD” Panel 1H13-P603 RCMS Power Distribution; Rev. A

Work Documents:
- WO 1264951-01; LOS-SC-Q1 U2 B SBLC Pump Quarterly Att. 2B; 11/30/2009
- WO 1286911-01; Rebuild / Reset SBLC Relief Valve 1C41-F029A; 11/25/2009
- WO 1280236; MM to Replace 2C41-F029B (SBLC) Pump Discharge Relief Vlv; 12/3/2009
- WO1280236 to Set 2C41-F029B (SBLC) Pump Discharge Relief Vlv per EC; 11/25/2009
- WO 1039245-01; RR Low Freq Motor/Generator Set Preventive Maint.; 6/25/2008
- Shift Log for 2/16-2010 – 2/21/2010
- EC 378797; Engineering Review of Various Spare Reactor Recirculation Pump Rotating Assembly Issues; Rev. 1
- OP-AA-106-101-1006; LaSalle 1B RR Pump T/S, Action Plan, OTDM Review; 1/15/2010
- LS-AA-125-1001; Root Cause Investigation Report for Unit 1 “B” Reactor Recirculation Pump Seal Degradation; 1/28/2010
- LOP-AA-03; Mode Change Checklist from Modes 3 or 5 to Mode 4; Rev. 25
- EC 378978; Evaluation of Running SDC with one RHR SW Pump; Rev. 00
- WO 99236697-12; MM 1E12-C300D Internal Pump Inspection (Pump Nozzle); 2/26/2010
- Preservice testing Special Instructions Checklist for Service Water Pump; 1st Quarter 2010
- LST-2007-004; RCMS Power Module (ELR1 & ELR2) Trip Circuit Checklist; Rev. 2
- LST-2007-004; Individual Control Rod Loop Check Checklist; Rev. 2

1R20 Outage Activities (71111.20)

Procedures:
- LIS-NB-115B;Unit 1 High Pressure Excess Flow Check Valve Operability Test (Test TAPS); Rev. 12
- LOA-DIKE-001; Lake Dike Damage/Failure; Rev. 8
- LOR-1PM10J-B504; Strong Motion Seismic Instrument System Initiated; Rev. 9

Issue Reports:
- 1027640; LVDTS Exhibit Significant Wear; 2/9/2010
- 1028554; Post-Seismic Event Walkdowns by Engineering; 2/10/2010
- 1029238; Wrong EFCV Tested During LIS-NB-115B; 2/12/2010
- 1030493; WHR Transition from Covered to Uncovered Worker for L1R13; 2/15/2010
- 1038085; L1R13 Drywell Closeout NRC Deficiencies > 740’ Elevations; 3/3/2010
- 1038161; NRC Id’d: Broken Tiewraps on Drywell Deck; 3/3/2010

Working Documents:
- ACE 1029238-05; Apparent Cause Evaluation: Investigate the wrong EFCV tested during LIS-NB-115B; 3/9/2010
- AR 1028433-02; Performance of Prompt Investigation of Work Hour Rule Violation – Shaw Millwrights; 2/13/2010

- AR 1028433-05; Quick Human Performance Investigation of Work Hour Rule Violation – Shaw Millwrights; 2/20/2010
- AR 1029238-02; Document Performance of Prompt Investigation (PINV). Attach Document; 2/16/2010

Drawings:
- M-93; P&ID Nuclear Boiler and Reactor Recirculating System; Rev. AP
- M-93; P&ID Nuclear Boiler and Reactor Recirculating System; Rev. AZ

Miscellaneous:
- 41.978^{o}N,88.597 ^{o}W; USGS Earthquake Details For Magnitude 4.3 Illinois Event; 2/10/2010 at 3:59:34 a.m.
- Human Performance Issue Verbal Report for LIS-NB-115B, Unit 1 High Pressure Excess Flow Check Valve Operability Test Event
- IR 1028433; Human Performance Issue Verbal Report – Work Hour Rule Violation – Shaw Millwrights; 2/10/2010
- IR 1029188; Equipment Prompt Investigation Report for Unit 1 Refuel Bridge Main Feed Cable Damaged; 2/11/2010
- L1R13 Fatigue Assessments; 3rd Qtr 2009 – 1st Qtr 2010
- NO-AA-104-1007;NOS LaSalle Site Status Report; 1/31/2010
- Paragon 1.2; Paragon Risk Model for Plant Conditions; 2/9/2010

<u>1R22 Surveillance Testing (71111.22)</u>

Procedures:
- LES-PC-101; Unit 1 Group 1 Isolation Logic System Functional Test; Rev. 13
- LES-DG-104; 1B Diesel Generator Trips and Trip Bypass Logic Test; Rev. 2
- LOS-HP-Q1; HPCS System In-service Test; Rev. 63
- LOS-DG-110; Unit 1 Integrated Division II Response Time Surveillance; Rev. 11
- LOS-DG-M2; 1A(2A) Diesel generator Operability Test; Rev. 79
- LOS-NB-R1; Reactor Vessel Leakage Test; Rev. 7
- LTS-100-38; RCIC Vacuum Discharge Isolation Valves Local Leak Rate Test 1(2)E51-F069 and 1(2) E51-F028; Rev. 13
- LTS-100-2; Local Leak Rate Test (LLRT), Flow Makeup Method; Rev. 32

Issue Reports:
- 1036690; Hydro- 1C11-D0223-127 Packing Leak 1 DPS; 2/28/2010
- 1036698; Hydro- 1C11-D5447-120 35 DPM Leak; 2/28/2010
- 1036806; CRD Flange Leakage Noted during Vessel Leakage Test; 3/1/2010
- 1036814; 40 DPM Leakage on Packing of 127 Valve; 3/1/2010
- 1036819; 20 DPM Leakage on 126 Valve Packing; 3/1/2010
- 1036829; 60 DPM on Limit Side Packing; 3/1/2010
- 1036833; Screwed Plug Between Group 11/12 Leaking 40 DPM; 3/1/2010
- 1036834; Screwed Plug Between Groups 12 and 13 Leaking 40 DPM; 3/1/2010
- 1036837; 20 DPM Leakage from Packing; 3/1/2010
- 1036842; Steady Stream of Water from Pump Seal; 3/1/2010
- 1036844; 24 DPM Leak From Valve Packing; 3/1/2010
- 1036845; 20 DPM From Packing; 3/1/2010
- 1036854; 6 DPM Leak from Valve Packing; 3/1/2010
- 1036855; 6 DPM Leak from Valve Packing; 3/1/2010

Working Documents:
- WO 1112008-01; EP LLRT, 1B21-F022A, 1B21-F028A, 1B21-F067A; 9/10/2009
- WO 1112735-01; “1B” DG Trips and Trip Bypass Logic Test; 3/4/2009

Drawings:
- 1E-1-4232AB; Schematic Diagram Primary Containment & Reactor Vessel Isolation System “PC” (B21H) Part 2; Rev. AA
- 1E-1-4203AF; Schematic Diagram Main Steam/Nuclear boiler Sys. NB (B21) Pt. 6; Rev. X
- 1E-1-4220AK; Schematic Diagram residual Heat removal System “RH” (E12) Part 10; Rev. Y

Miscellaneous:
- LES-PC-101; Unit RO Shiftly Surveillance Sheets: Short Duration Time Clock Log, Unit 1
- LSCS-UFSAR Table 8.3-1; Loading on 4160-Volt Buses; Rev. 17
- LSCS-UFSAR Table 8.3-2; Summary of Relay Protection for ESF 4160-Volt Equipment
- Operations Outage Control Center Log; 2/18 – 2/19/2010

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

Procedures:
- RP-AA-376; Radiological Posting, Labeling and Marking Standard; Rev. 4
- RP-AA-460; Controls for High and Locked High Radiation Areas; Rev. 17

Issue Reports:
- 1006449; Nuclear Oversight Identified Radiation Protection Focused Area Self-Assessment Issues; 12/16/2010
- 1010185; Secured High Radiation Area Not Secured; 12/29/2009
- 1010216; RP-AA-460 Access Control Not Meeting Expectations; 12/29/2009
- 1011381; Discovery of High Radiation Area; 1/1/2010
- 10203006; High Radiation Area Identified In Unit 1 Reactor Building 786; 1/23/2010
- 1022050; Reactor Water Clean-Up Leaks Challenge Contamination Control; 1/25/2010
- 1027536; Radiation Protection Correction Specialist; 2/8/2010
- 1027591; Failure to Count Reactor Head Piping Breach Noble Gas Air Sample; 2/8/2010
- 1023719; Worker Alarms Radiologically Restricted Area Exit Monitor; 1/27/2010
- 1023783; Electronic Dosimeters Enter Reset; 1/30/2010
- 1028886; High Radiation Area Swing Gate Found Unlocked; 2/11/2010
- 1029633; Request Work Order to Expand Locked High Radiation Area Fencing Prior to L2R13; 2/12/2010
- 1029917; Secured High Radiation Area and Radworker Practices; 2/12/2010
- 1030044; Nuclear Oversight Identified Radworkers Not Using Radiation Monitors; 2/13/2010
- 1030355; L1R13 Lessons Learned Refuel Floor–Drywell Coordination; 2/15/2010
- 1030423; Personnel Contamination; 2/14/2010
- 1030539; Nuclear Oversight Identified Radworkers Not Using Radiation Monitors; 2/15/2010
- 1032934; Area Posted As A High Radiation Area; 2/17/2010

2RS2 Occupational ALARA Planning and Controls (71124.02)

Procedures:
- RP-AA-401; Operational ALARA Planning and Control; Rev. 9
- RWP 10010624; Drywell Safety Relief Valve Activities; Rev. 0
- RWP 10010637; Under Vessel Nuclear Instrumentation; Rev. 0
- RWP 10010638; Control Rod Drive Pull/Put under Vessel Activities; Rev. 1

- RWP 10010646; L1R13 Drywell In-Service Inspection (Nozzle Inspection) Activities; Rev. 0
- RWP 10010657; Unit 1 Recirculation Pump and Motor Repair; Rev. 0

Issue Reports:
- 997619; L1R13 Drywell Emergency Core Cooling System Flush Dose Impact; 11/24/2009
- 1021342; Nuclear Oversight Identified Elevation of Station ALARA Program; 1/25/2010
- 1028513; L1R13 Lessons Learned Unexpected High Pressure Turbine Shell Dose; 2/10/2010
- 1028656; Lead Re-Work in the Drywell; 2/10/2010
- 1031028; RWP 10010716 to Exceed Original Radiation Work Permit Estimate; 2/16/2010

Miscellaneous:
- FASA 848243-03; Focused Area Self-Assessment: Radiation Protection Access Control and ALARA; 11/20/2009

4OA1 Performance Indicator Verification (71151)

Miscellaneous:
- Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences for January through December 2009
- Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours for January through December 2009
- NEI 99-02; Regulatory Assessment Performance Indicator Guideline; Rev. 5

4OA2 Identification and Resolution of Problems (71152)

Procedures:
- ER-AA-380; Primary Containment Leakrate Testing Program; Rev. 7

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- 1030273; Rod Block Monitor Inconsistency; 2/14/2010
- 1030806; Unsat MOV Grease Sample; 2/15/2010
- 1029962; Steam Cutting Found Across Bypass Valve #3 Seat; 2/13/2010
- 1034693; Leak Found During LTS-300-09 Testing 710’ B-12 16’ Up; 3/1/2010
- 2036525; Cannot Select ‘Shell Warming’; 2/28/2010
- 1036649; U-1 3B RR Breaker Failed to Close; 2/28/2010
- 1027102; Missed LIS-RR-105A Surveillance Data; 2/8/2010
- 459052; LLRT 1VQ036 As Found Test Exceeded the Admin Warning Limit; 2/26/2006
- 735862; LLRT 1VQ036 As Found Test Exceeded the Admin Warning Limit; 2/13/2008
- 1032009; L1R13 LLRT On 1VQ036 Exceeded Admin Alarm Limit; 2/17/2010
- 1036280, Bushings for 1B21-F032A; 2/26/2010

Issue Reports Resulting from NRC/IEMA Inspection:
- 1018455; NRC Identified Issue – Cart Blocking Stairs; 1/19/2010
- 1018454; NRC Identified Issue – Leak from 1E12-R529; 1/19/2010
- 1038161; NRC Id’d: Broken Tiewraps on Drywell Deck; 3/3/2010
- 1026176; NRC Identified: Housekeeping Issue U1 RB; 2/4/2010
- 1018454; NRC Identified Issue – Leak from 1E12-R529; 1/19/2010
- 1022445; NRC Request for ATWS Documents; 1/28/2010
- 1031379; NRC ID: Door 320 Continuously Unlatching; 2/16/2010
- 1026530; U1 RB 740 Housekeeping; 2/5/2010
- 1032176; NRC ID: Housekeeping Issue U1 RB; 2/4/2010

- 1032796; NRC Observation: L1R13 heater Bay; 2/19/2010
- 1036854; GDPM Leak from Valve Packing; 3/1/2010
- 1036855; GDPM Leakage from Valve Packing; 3/1/2010
- 1038089 L1R13 Drywell closeout NRC Deficiencies > 740' Elevations; 3/3/2010
- 1040288; Find DW Closeout with NRC on 740 Elevation; 3/9/2010

Drawings:
- M-92; P&ID Primary Containment Vent & Purge; Rev. AS
- M-93; P&ID Nuclear Boiler & Reactor Recirculating System; Rev. AX

Miscellaneous:
- NEI 94-01; Nuclear Energy Institute Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J; 12/8/2005
- L1R13 PORC; Engineering Topics; 1st Quarter 2010
- 022; Reactor Recirculation Activities/Notes Training Documentation
- Local Leak Rate Testing History for 1VQ036; 2/21/1991- 2/18/2010

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
ALARA	As-Low-As-Is-Reasonably-Achievable
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
BWR	Boiling Water Reactor
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CRD	Control Rod Drive
CSCS	Core Standby Cooling System
DG	Diesel Generator
ECCS	Emergency Core Cooling System
EFCV	Excess Flow Check Valve
EDG	Emergency Diesel Generator
HCU	Hydraulic Control Unit
HEPA	High-Efficiency Particulate Air
HPCS	High Pressure Core Spray
HRA	High Radiation Area
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Issue Report
ISI	In-service Inspection
IST	In-service Test
LERF	Large Early Release Frequency
LLRT	Local Leak Rate Testing
LPCI	Low Pressure Coolant Injection
LPCS	Low Pressure Core Spray
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NDE	Nondestructive Examinations
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OSP	Outage Safety Plan
P&ID	Piping and Instrumentation Diagram
PARS	Publicly Available Records
PI	Performance Indicator
PMT	Post-Maintenance Testing
psig	Pounds Per Square Inch Gauge
RCIC	Reactor Core Isolation Cooling
RCMS	Reactor Control Management System
RFO	Refueling Outage
RHR	Residual Heat Removal
RP	Radiation Protection
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RR	Reactor Recirculation
RWP	Radiation Work Permit
SAT	Station Auxiliary Transformer
SBLC	Standby Liquid Control
SDP	Significance Determination Process

SRA	Senior Reactor Analyst
SSC	Systems, Structures, and Components
SW	Service Water
TI	Temporary Instruction
TRM	Technical Requirements Manual
TS	Technical Specification
UT	Ultrasonic Examination
UFSAR	Updated Final Safety Analysis Report
VHRA	Very High Radiation Area
WO	Work Order

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Sincerely,

/RA By Nirodh Shah Acting For/

Kenneth Riemer, Chief
Branch 2
Division of Reactor Projects

Docket Nos. 50-373; 50-374
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NRC INTEGRATED INSPECTION REPORT 05000373/2010002;
05000374/2010002

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