La Salle 1
3Q/2010 Plant Inspection Findings

Initiating Events

Significance: G Feb 11, 2010
Identified By: Self-Revealing
Item Type: NCV NonCited Violation
Improper Procedure Implementation During Testing of Excess Flow Check Valve
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.
Analysis: 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)
Enforcement: 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)

Inspection Report# : 2010002 *(pdf)*

Mitigating Systems

Significance: G Jun 30, 2010
Identified By: NRC
Item Type: NCV NonCited Violation
Failure to develop and implement an adequate surveillance test procedure to accurately assess the as found trip setpoint for the pressure switches associated with the main steam line low pressure isol
This NCV is for licensee failure to develop and implement an adequate surveillance test procedure to accurately assess the as found trip setpoint for the pressure switches associated with the main steam line low pressure isolation function and various other safety-related functions.
During a followup review of Task Interface Agreement 2009 006 “Unacceptable Preconditioning of Safety Related Pressure Switches During Required Surveillance Testing at Montcello” issued by the NRC in September 2009, the inspectors identified that the licensee’s surveillance testing procedures established a methodology which tested various safety related pressure switches in a manner which was deemed unacceptable preconditioning by the NRC. In particular the inspectors noted that during the LIS MS 101A(201A) procedure, “Unit 1(2) Main Steam Line Low Pressure MSIV Isolation Calibration in Run Mode” Revision 5, the pressure switches in question were initially subject to main steam pressure. In accordance with the surveillance procedure, the inspectors noted that the basic testing methodology associated with these pressure switches was as follows: 1) isolate the pressure switch to be tested; 2) uncap the test connection; 3) connect the test equipment to the test connection; 4) increase the pressure until the pressure switch resets and record the reset test data; 5) bleed off the pressure until the pressure switch trips and record the as found trip setpoint; 6) remove the test equipment and restore the pressure switch to operation. This testing methodology caused the pressure switch and associated contacts to change state when the system pressure was relieved in Step 2; again when pressure was applied to reset the pressure switch in Step 4; then a third time when the pressure was bled off to obtain the as found trip setpoint in Step 5. This testing methodology subjected the pressure switch to a maximum pressure differential (operating pressure to atmospheric) and fully cycled the pressure switch prior to obtaining the as found trip setpoint data. This particular surveillance was most recently performed on unit 1 MSIV pressure switches on April 16, 2010 and on unit 2 MSIV pressure switches on June 11, 2010. The inspectors review also identified that no engineering justification had been performed by the licensee to show that testing of

these pressure switches in the above manner did not impact the accuracy and reliability of the safety related pressure switches.
The inspectors noted that the existing licensee pressure switch testing methodology ensured operability of the pressure switches subsequent to the performance of the applicable surveillance test, since the required as left pressure switch setpoint was adjusted (if required) prior to the completion of the surveillance. The inspectors determined that the existing testing methodology potentially masks existing conditions; such as sticking contacts, mechanical binding, and setpoint drift; and could mask existing operability concerns because the pressure switch is fully cycled prior to obtaining the as found trip setpoint data.
Inspection Manual Chapter (IMC) 9900 states, in part, that unacceptable preconditioning is defined as the alteration, variation, manipulation or adjustment of the physical condition of a SSC before or during TS surveillance or American Society of Mechanical Engineers code testing that will alter one or more of SSCs operational parameters, which results in acceptable test results. Such changes could mask the actual as found condition of the SSC and possibly result in an inability to verify the operability of the SSC. In addition, unacceptable preconditioning could make it difficult to determine whether the SSC would perform its intended function during an event in which the SSC might be needed. Therefore, the inspectors concluded that since the licensee had not performed an evaluation which justified that the preconditioning of the pressure switches was acceptable, the licensee’s surveillance testing methodology which cycles a pressure switch prior obtaining as found trip setpoint data constituted unacceptable preconditioning of the pressure switch.
Further investigation by the inspectors revealed that an additional 36 pressure switches in Units 1 and 2, which are relied upon to initiate TS related protective functions in the areas of emergency core cooling system low pressure injection permissive, TCV fast closure, main condenser low vacuum scram, reactor core isolation cooling (RCIC) steam low pressure isolation, and reactor high pressure shutdown cooling isolation were tested in a manner similar to that described above with no engineering justification.
Analysis: The inspectors determined that the failure to develop and implement an adequate surveillance test procedure to accurately assess the as found trip setpoint for the pressure switches associated with the main steam line low pressure isolation function and other safety related functions constituted a performance deficiency warranting significance evaluation in accordance with IMC 0612, Appendix B, “Issue Disposition Screening.” The inspectors determined that the performance deficiency was more than minor and a finding because it impacted the Reactor Safety Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences and affected the cornerstone attribute of Equipment Performance. The inspectors did not identify any cross cutting aspects associated with this finding.
The inspectors evaluated the finding using IMC 0609, Appendix A, Attachment 1, “Significance Determination of Reactor Inspection Findings for At Power Situations,” using the Phase 1 Worksheet for the Initiating Events Cornerstone. Since the inspectors answered all of the Exhibit 1, Table 4a Mitigating Systems questions no, the inspectors concluded that the finding was of very low safety significance.
Enforcement: Title 10 CFR, Part 50, Appendix B, Criterion V “Instructions, Procedures and Drawings”, states, in part, that activities affecting quality shall be prescribed by documented instructions of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, most recently on June 11, 2010, the licensee failed to prescribe a documented instruction that was appropriate to the circumstances for the testing of the pressure switches for the Main Steam Low Pressure Group I Isolation, an activity affecting quality. Specifically, Procedure LIS MS 201A incorporated a testing methodology that inappropriately manipulated the pressure switches prior to obtaining as found data, thus resulting in unacceptable pre conditioning. Because this violation was of very low safety significance and was entered into the licensee’s CAP (Issue Report (IR) 988976), it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy.

Inspection Report# : 2010003 *(pdf)*

Significance: G Mar 31, 2010
Identified By: NRC
Item Type: NCV NonCited Violation
Failure to Maintain Design Control of SBLC system
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 the 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 ten years. This was the practice at LaSalle, so a maximum of ten 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 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 an 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).

Inspection Report# : 2010002 *(pdf)*

Barrier Integrity

Emergency Preparedness

Occupational Radiation Safety

Public Radiation Safety

Physical Protection

Although the NRC is actively overseeing the Security cornerstone, the Commission has decided that certain findings pertaining to security cornerstone will not be publicly available to ensure that potentially useful information is not provided to a possible adversary. Therefore, the cover letters to security inspection reports may be viewed.

Miscellaneous

Significance: N/A Nov 20, 2009
Identified By: NRC
Item Type: FIN Finding
PI&R Report Summary
Overall, the corrective action program (CAP) was being effectively implemented. Issues were identified at a low threshold, evaluated and corrected. Self-assessments and audits by Nuclear Oversight (NOS) were thorough and critical of the assessed areas. Operating experience was recognized as valuable and was effectively communicated. Interviews with licensee staff and a review of the Employee Concerns Program (ECP) indicated that the licensee had a positive safety culture environment that encouraged identification of issues in the CAP.
However, the inspectors identified several areas of concern that may negatively impact the licensee's ability to identify and resolve issues. In some cases, these issues had been recognized by the licensee, but effective corrective action had not been taken. Briefly, the issues were:
• The current CAP performance indicators were not always effectively used or sufficient to monitor the program. Although the licensee was aware of these issues, CAP staff appeared willing to live with the shortcomings and had not formally taken corrective action.
• There were some examples of long-standing issues that were either not corrected or not evaluated. In some cases, the licensee had identified the issues, but had not evaluated why previous corrective actions were ineffective.
• There were several examples where the review of operating experience (OE) in cause evaluations were not documented in accordance with licensee procedures. Additionally, there was no formal requirement to evaluate whether the failure to use OE was a precursor during the evaluation of events. Although the licensee had identified these issues in the CAP, the corrective actions were somewhat limited.
• Issues that were reviewed by the ECP, but not captured in a formal case file, were not always well documented. This resulted in some uncertainty regarding whether potentially significant issues were appropriately dispositioned.

Inspection Report# : 2009007 *(pdf)*