October 19, 2001

Mr. Oliver D. Kingsley, President
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: LASALLE COUNTY STATION UNIT 2
NRC SPECIAL INSPECTION REPORT 50-374/01-017(DRP)

Dear Mr. Kingsley:

On September 19, 2001, the NRC completed a Special Inspection concerning a reactor scram at your LaSalle County Station. The enclosed report presents the results of that inspection. The results of this inspection were discussed on September 19, 2001, with Mr. C. Pardee and other members of your staff.

On September 3, 2001, LaSalle Unit 2 was manually scrammed from 100 percent power by a control room operator in response to a rapidly decreasing water level in the Reactor Pressure Vessel (RPV). Your initial investigation determined that two fuses had opened, causing feedwater controller demand to rapidly decrease to zero. Numerous materiel condition and equipment performance problems were noted during this event: 1) the fuses, located in a 4160 Vac safety-related bus, opened without an external event that would have caused them to open (short circuit or ground), 2) the Reactor Core Isolation Cooling (RCIC) system suffered a water hammer event, 3) the valve position indication for the RCIC Outboard Check Valve displayed an open indication when the valve was apparently shut, 4) the Condensate Storage Tank (CST) suffered two small roof ruptures and overflowed very slightly radioactive water onto the ground around the tank, and 5) the condenser hotwell reject valves did not adequately control condenser hotwell level.

In addition to the materiel condition and equipment performance problems, a number of operator performance weaknesses were displayed subsequent to the reactor scram: 1) control room operators allowed High Pressure Core Spray (HPCS) and RCIC to automatically trip on RPV high water level vice attempting to manually control RPV water level at or near the normal operating level band, 2) after shutting the main steam isolation valves, the operating crew did not re-open the main steam line isolation valves to re-establish the main condenser as the heat sink, 3) an operating crew did not recognize the requirements for entering a Technical Specification relative to pressure isolation valves, 4) the crew failed to execute procedural requirements when required by plant conditions, 5) the crew was slow to conduct a shut-down risk assessment, and 6) the initial risk assessment was incorrect and delayed establishment of a protected emergency systems train.

Based on the risk and deterministic criteria specified in Management Directive 8.3, "NRC Incident Investigation Program," and Inspection Procedure 71153, "Event Followup," and due to the equipment and operator performance problems which occurred, a Special Inspection was initiated in accordance with Inspection Procedure 93812, "Special Inspection," to evaluate the facts and circumstances surrounding the event as well as the actions taken by your staff in response to the system performance issues encountered. The inspection focused on: 1) the sequence of events for this reactor scram, 2) the root cause evaluation for the loss of the 241Y Bus, 3) a review of your proposed corrective actions for this event, 4) a review of the April 6, 2001, reactor scram for similarities, 5) the extent of damage to the Condensate Storage Tank and the conditions that led to the failure, 6) the extent of damage/potential damage to the RCIC system, 7) the cause of the unavailability of the turbine-driven reactor feed pumps during the reactor scram, and 8) operator actions associated with RPV level control and restoration of the power conversion system in response to the event.

Based on the results of this inspection, the inspectors identified one issue of very low safety significance (Green) and an associated Non-Cited Violation (NCV) for failure to correctly execute procedural steps in an abnormal operating procedure. If you deny this NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region III, 801 Warrenville Road, Lisle, Illinois 60532-4351; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspectors' Office at the LaSalle County Nuclear Generating Station.

Although none of the materiel condition issues or human performance errors described in the report are individually safety significant, when taken collectively, they represent challenges to the operators as well as concerns regarding the extent of understanding by plant personnel of plant design and operators' knowledge of plant operating characteristics. Also noteworthy were the number and frequency of material condition issues that have occurred at the LaSalle Station. The corrective actions implemented after the April 6, 2001,scram, that also resulted in a special inspection, do not appear to have been completely effective, particularly with respect to limiting human performance errors and improving plant materiel condition. This is further supported by the occurrence of another scram on September 6, 2001, which was the result of a human performance error on the part of a control room operator. Correction of these persistent and repetitive problems will necessitate your careful attention, particularly to the effectiveness of any proposed corrective actions. The September 6, 2001, scram will be addressed in a routine inspection report. Also, several issues in this report, including the RCIC outboard check valve position indication problems were evaluated as part of the Problem Identification and Resolution Inspection and will be documented in Inspection Report 2001-16.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/ index.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Geoffrey Grant, Director
Division of Reactor Projects

Docket No.: 50-374
License No.: NPF-18

Enclosure: Inspection Report 50-374/01-017(DRP)

cc w/encl: W. Bohlke, Senior Vice President, Nuclear Services
C. Crane, Senior Vice President - Mid-West Regional
J. Cotton, Senior Vice President - Operations Support
J. Benjamin, Vice President - Licensing and Regulatory Affairs
R. Hovey, Operations Vice President
J. Skolds, Chief Operating Officer
R. Krich, Director - Licensing
R. Helfrich, Senior Counsel, Nuclear
DCD - Licensing
C. Pardee, Site Vice President
M. Schiavoni, Station Manager
W. Riffer, Regulatory Assurance Supervisor
M. Aguilar, Assistant Attorney General
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REGION III

Docket No:	50-374
License No:	NPF-18
Report No:	50-374/01-017(DRS)
Licensee:	Exelon Generation Company
Facility:	LaSalle County Station, Unit 2
Location:	2601 N. 21st Road Marseilles, IL 61341
Dates:	September 5 through September 19, 2001
Inspectors:	Dell McNeil, Reactor Inspector Desiree Smith, Dresden Senior Resident Inspector
Approved by:	Bruce Burgess, Chief Branch 2 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000374037-01-017, on 09/19/2001, Exelon, LaSalle County Station, Unit 2; Special Inspection

This special inspection examined the facts and circumstances surrounding a Unit 2 manual scram which occurred on September 3, 2001, as a result of fuse failures in the undervoltage/degraded voltage protection system for the 241Y 4160V Safety-Related Bus.

The members of the special inspection staff included a reactor engineer from the RIII Operations Branch and the Dresden Station Senior Resident Inspector. Input was also provided by a RIII Senior Reactor Analyst and the LaSalle County Station NRC resident staff. One Green finding was identified. The significance of a finding is indicated by its color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMS) 0609, "Significance Determination Process" (SDP). The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OERSIGHT/index.html. Findings for which the SDP does not apply are indicated by "No Color" or by the severity level of the applicable violation.

A. Inspector Identified Findings

Cornerstones: Barrier Integrity

Green. The inspectors identified a Non-Cited Violation for the failure of operators to execute all of the required steps of the abnormal procedure for isolating the control rod drive system following a trip of the reactor recirculation pumps.

This finding was of low safety significance. Although the Technical Specification limits were exceeded, actual reactor conditions did not exceed the parameters contained in the design thermal stress analysis and the excessive heatup rate was determined to not be a threat to the integrity of the reactor fuel. (Section 1R6)

B. Licensee Identified Findings

No findings of significance were identified.

Report Details

Summary of Plant Event

On September 3, 2001, at approximately 5:28 p.m., feedwater flow control on LaSalle County Station Unit 2 decreased rapidly to zero as a result of the failure of two of four fuses providing power to the feedwater flow control stations. Operators attempted to take manual control of the feedwater control stations but were unable to do so because of the loss of voltage to the stations. Operators then determined that Reactor Pressure Vessel (RPV) water level was decreasing below +20 inches in an uncontrolled manner and scrammed the reactor in accordance with station procedures.

The two fuses also provided power to the safety-related 241Y Bus Undervoltage and Degraded Voltage relays. When these relays de-energized, breakers tripped, which isolated the 241Y Bus from all station power supplies, a start signal was sent to the ‘0' Emergency Diesel Generator (EDG), and a constant undervoltage trip signal was initiated and maintained to all large loads powered by the 241Y Bus to prevent overload of the ‘0’ EDG.

The ‘0' EDG started, connected to, and re-energized 241Y Bus. Operators were then confused at the contradictory indications of 241Y Bus status. The "bus alive" light that indicated bus energized status was lit, but not at full intensity. The EDG’s output breaker indicated shut, its output voltage was 4160V, and its frequency was 60 Hz. Some 241Y Bus equipment had re-energized, yet a bus low voltage alarm was continuously alarming and would not reset. When operators attempted to start the 2A Residual Heat Removal (RHR) pump, the pump’s breaker closed and immediately tripped on the undervoltage signal being maintained by the 241Y Bus undervoltage protection relays.

Reactor pressure vessel water level continued to fall until the vessel Low Low Level setpoint was reached. At this vessel water level, Reactor Core Isolation Cooling (RCIC) and High Pressure Core Spray (HPCS) automatically initiated and all containment cooling automatically tripped. This resulted in a rapid refilling of the RPV and a rapid increase in containment temperature and pressure.

Reactor Core Isolation Cooling and HPCS automatically tripped when RPV water level reached +55.5 inches. Water level continued to rise as a result of the continuing injection of control rod drive hydraulics water and the expansion of the relatively cold water as it was heated by the hot reactor core. When RPV water level reached +73 inches, operators manually shut the Main Steam Isolation Valves (MSIVs) in accordance with plant procedures.

Six minutes after the event initiation, drywell pressure increased above 0.75 psig due to the loss of containment cooling. Operators had not seen drywell pressure rise this rapidly due to a loss of drywell cooling during simulator training and initially became concerned about the possibility of a small steam leak inside the drywell. Operators correctly determined that there was not a steam leak and the high containment pressure was caused by the rapidly increasing temperature in the drywell. Containment cooling (VP) was restored and drywell pressure began to decrease immediately.

Operators started the motor-driven reactor feed pump and controlled RPV water level through the low-flow feedwater regulating valve. Reactor pressure vessel water level was occasionally controlled by periodically using the RCIC system in the injection mode when condenser hotwell level was below its normal water level. When the RCIC system was not being used in the injection mode, it was used to control reactor pressure. At other times reactor pressure was controlled by using safety relief valves or by venting steam through main steam line drains to the main condenser.

After the main turbine tripped, feedwater cascaded from the feedwater heaters to the main condenser causing condenser water level to rise rapidly. Condensate reject valves opened and diverted water from the main condenser to the Condensate Storage Tank (CST). This resulted in a significant amount of condenser water being moved to a CST that was already at the high end of the operating water level band. The introduction of this large amount of condensate filled the CST to the CST top and caused additional pressure on the CST top which resulted in two eighteen to twenty-four inch splits along the edge of the lid and the overflow of 25,000 - 45,000 gallons of very slightly radioactive water. Operators responded to the overflow by manually shutting condensate reject manual isolation valves.

Approximately 3½ hours after the event initiation, Operations Analysis Department personnel reported to shift management that it was possible there were blown fuses in 241Y Bus. The Unit Supervisor informed the control room operators that no Division I pumps would be available. Nine hours after the event initiation, the open fuses in 241Y Bus were replaced, but one fuse that was known to have high resistance opened when it was placed in service. This necessitated the authorization of a non-like-for-like fuse replacement and the bus was re-energized with a new fuse from stores and an old fuse that had been in the bus earlier and retained by the system engineer.

Some equipment performance problems were noted during the event:

- the fuses that opened on the 241Y Bus did so without an external event that would have caused them to open (short circuit or ground)
- the RCIC system suffered a water hammer event
- 2E51-F065, RCIC Outboard Check Valve, position indication displayed an open indication when the valve was apparently shut
- the CST suffered two small roof ruptures and very slightly radioactive water overflowed onto the ground around the tank
- the condenser hotwell reject valves did not adequately control condenser hotwell level leading to the CST roof ruptures
- safety relief valve position indication for three safety relief valves was erroneous

Some operator performance weaknesses were displayed subsequent to the reactor scram:

- control room operators allowed HPCS and RCIC to automatically trip on RPV high water level vice attempting to manually control RPV water level at or near the normal operating level band

- after shutting the MSIVs, the operating crew did not re-open the MSIVs to re-establish the main condenser as the heat sink

- an operating crew failed to recognize the requirements for entering a technical specification relative to pressure isolation valves

- the crew failed to execute plant procedures when required by plant conditions

- the crew was slow to initiate a shut-down risk assessment

- the initial risk assessment was incorrect and delayed establishment of a protected emergency systems train.

Based on the risk and deterministic criteria specified in Management Directive 8.3, "NRC Incident Investigation Program," and Inspection Procedure 71153, "Event Followup," and due to the equipment performance problems which occurred, a special inspection was initiated in accordance with Inspection Procedure 93812, "Special Inspection." The purpose of the Special Inspection was to evaluate the facts and circumstances surrounding the event as well as the actions taken by licensee personnel in response to the event. The inspection focused on the following:

1. development of a sequence of events for this reactor scram

2. review the root cause evaluation of the loss of the 241Y Bus

3. review of the licensee's proposed corrective actions for this event

4. review the April 6, 2001, reactor scram for similarities, including RCIC check valve position indication and RCIC flow oscillations

5. determine the extent of damage to the CST and the conditions that led to the failure

6. determine the extent of damage/potential damage to the RCIC system

7. determine the cause of the unavailability of the turbine-driven reactor feed pumps during the reactor scram

8. assess operator actions associated with RPV water level control and restoration of the power conversion system in response to the event.

1. **REACTOR SAFETY**

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R1 Sequence of Events/Root Cause Evaluation

a. Inspection Scope

The inspectors developed a sequence of events and reviewed the root cause of the initiating event for the loss of the Unit 2 Engineered Safety Features 4KV Division 1 241Y Bus.

b. Findings

No findings were identified during this inspection.

Sequence of Events

The inspectors reviewed logs, alarm printouts, and other documentation, interviewed operators who initiated the scram, system engineers, and operations training instructors, and developed the following sequence of events for the September 3, 2001, LaSalle County Station Unit 2 reactor scram:

17:28:28 Two ‘B’ phase fuses open causing an Undervoltage on 241Y Bus
- No fast transfer of power supplies because of rate of change of voltage
- 2A VP (Containment Cooling) Chiller Trips
- Feed Water Valve control signal failure low (does not lock-up because of rate of decline of voltage) Signal failure drives feed pump speed to zero
- Nuclear Station Operator (NSO) takes feedwater (FW) to manual, determines manual is ineffective
- NSO attempts to use backup controllers
- Emergency operation procedures (EOPs) entered on low RPV water level

17:28:29-42 Manual Scram initiated by NSO
‘0' EDG starts on low voltage, connects to, and energizes 241Y Bus
- Bus alive light is energized but very dim
- Some loads on 241Y Bus are re-energized

17:28:45 RPV water level reaches Low Low Level
- HPCS/RCIC auto start
- ATWS trip initiates (reactor recirculation (RR) pumps trip)

17:32:58 HPCS/RCIC automatically trip on Level 8

17:34:00 Drywell pressure increases above 0.75 psig

17:40:00 Suppression pool temperature exceeds 105°F - EOPs entered.

- 2A Residual Heat Removal (RHR) pump will not start, declared inoperable.
- 2B RHR placed in suppression pool cooling.

17:48:55 NSO shuts MSIVs on high RPV water level (73 inches)

- Safety Relief Valves (SRVs) used to control RPV pressure (intermediate position indication on three SRVs after operation)

17:55:00 Drywell pressure decreases below 0.75 psig

18:20:00 Motor driven reactor feed pump started and controlling RPV water level through the low-flow feedwater regulating valve

18:35:00 Suppression pool temperature is 109°F

18:55:00 RCIC restarted to control vessel level. RCIC placed in manual to control flow oscillations (expected oscillations during transition between pressure control and injection modes)

19:14:00 Operators using main steam line drains to control reactor pressure

20:10:00 Operators determine they are not in Technical Specification 3.4.6 for reactor coolant system pressure isolation

20:15:00 RCIC is in pressure control, RPV water level is being maintained by the Motor Driven Reactor Feedwater Pump (MDRFP) and the low-flow feedwater regulating valve.

20:30:00 Suppression pool temperature greater than 120°F

20:47:00 OAD (Operations Analysis Department) reports possible fuses blown in 241Y Bus, Unit Supervisor informs control room operators that no Division I pumps will be used

21:57:00 Group I isolation on low condenser vacuum

22:12:00 Low Condenser Vacuum Isolation reset, main steam line drains reopened to establish RPV pressure control

22:23:00 Operators again determine they are not in Technical Specification 3.4.6

01:18:00 RCIC is placed in standby

03:00:00 Blown fuses in 241Y Bus are replaced but bus not restored (one fuse opened upon loading)

04:07:00 Fuses installed in 241Y Bus (non-like-for-like replacement authorized by the shift manager)

04:35:00 Electrical buses re-energized

Root Cause Review

The licensee determined that the 4KV Engineered Safety Features 241Y Bus had experienced actuation of its associated Division 1 undervoltage protective circuit. Control room indications showed bus A-C phase reading was 4200V while the other two phase readings (A-B, B-C) were approximately ½ of the A-C phase reading. Bus 241Y had two potential transformers in the undervoltage/degraded voltage protection scheme. One potential transformer had one fuse protecting the A phase and another fuse protecting the B phase, the second potential transformer had one fuse protecting the C phase and another fuse protecting the B phase. The B phase fuses were cross-connected before and after the fuses. Undervoltage/degraded voltage protection for 241Y Bus required the activation of two undervoltage or two degraded voltage relays. The simultaneous failure of the A and C phase fuses, or the simultaneous failure of both B phase fuses, would initiate both channels of undervoltage/degraded voltage protection circuitry.

In this event, both 'B' phase fuses opened, activating the 241Y Bus undervoltage relays. The undervoltage relays initiated signals to start the '0' EDG and to trip 241Y Bus loads including the following:

- the low pressure core spray pump
- the 2A RHR pump
- the 2A primary containment water chiller

Troubleshooting activities conducted by the licensee indicated that the cause of the blown fuses was <u>not</u> due to an overcurrent condition, nor to a failure of the undervoltage/degraded voltage protective action circuitry.

After troubleshooting activities, four fuses were withdrawn from the storeroom, three of the fuses were found to have high resistance. Electricians installed the one good fuse from the storeroom and one of the new fuses with high resistance. The A and C phase fuses, which had not failed during this event, were re-installed. When voltage was applied to the circuit the new, high resistance fuse opened. The opened fuse was then replaced with a fuse maintained by a system engineer that had been removed from the same circuit during an earlier preventive maintenance activity. The licensee had executed a pre-defined preventive maintenance activity to replace the fuses in applicable plant systems. The safety-related 241Y Bus fuses were replaced in November 2000. The licensee performed continuity checks and megger tests on the fuses prior to installing them in 241Y Bus. The licensee believed this meggering activity may have potentially damaged the fuses prior to installation. Electrical Maintenance personnel have discontinued meggering fuses prior to installation.

When voltage was re-applied to the circuit, none of the fuses opened. The undervoltage protective circuitry powered through these fuses was then re-tested and returned to service. All four of these fuses were subsequently replaced with acceptable replacement fuses.

As part of the licensee's investigation of the fuse failures, the licensee sent one failed B phase fuse and one high resistance fuse retrieved from the storeroom to their own testing facility. The other B phase fuse and another high resistance fuse retrieved from the storeroom were sent to the vendor. The licensee's investigation showed that the failed B phase fuse was missing a ½" section of fuse wire a short distance from one end of the fuse wire, which indicated a minor overcurrent condition occurred. The licensee's examination of the high resistance fuse from the storeroom indicated the fuse wire was physically broken and had signs of oxidation near one of the end caps. The vendor's investigation of the failed fuses indicated similar results on the B phase blown fuse; the high resistance fuse taken from the storeroom had indications of a sudden over-current condition.

The licensee had not completed the full root cause of the fuse failures at the time of the inspection conclusion. The licensee's initial prompt investigation indicated that the failure was related to the fuses and not a condition caused by the undervoltage protective circuitry. Poor performance of the fuses, as-found degraded fuse condition upon retrieval from the storeroom, and undervoltage protective circuitry testing results supported the licensee's hypothesis that this event was caused by fuse failure. Because final results of the fuse testing had not been completed, the licensee had not completed an evaluation of the need for a 10 CFR 21 notice. The licensee initiated Condition Report (CR) #2001-05247 to track the fuse failures and the possible need for a 10 CFR 21 notice.

Station personnel believed the potential existed for a fuse program problem since the fuse retrieval process (with meggering) may have been damaging the fuses prior to their installation. Concurrent with these testing efforts, the licensee was pursuing implementation of a modification for separating the downstream cross-connect between the B phase fuses. The licensee was also considering installing additional monitoring equipment to detect a potential intermittent failure. The licensee was still evaluating the station's fuse program and the potential design flaw of the 241Y Bus fuse arrangement when the inspection concluded.

1R2 April 2001 Event/Licensee Corrective Actions

a. Inspection Scope

The inspectors assessed the licensees' corrective actions for a similar event in April 2001, where problems were experienced with the RCIC system, and evaluated the station's corrective actions for this event.

b. Findings

Open Reactor Core Isolation Cooling Injection Check Valve Indication

During the April 2001, reactor scram on Unit 2, the RCIC system outboard and inboard injection check valves indicated open when they should have indicated closed. In an attempt to restore proper valve position indication during the April event, operators executed the Reactor Core Isolation Cooling System Isolation and System Shutdown operating procedure (LOP-RI-03), Section E.2 which caused reverse flow through the RCIC system. After LOP-RI-03, Section E.2, was completed, only the outboard injection check valve, 2E51-F065, displayed closed indication. The licensee then slightly rotated the position indicating rod for the inboard check valve, 2E51-F066, which caused it to make up with the limit switches and provide closed indication. The licensee's actions were documented in RCIC 99274402-01 and the check valve closure problem was entered as Operator Work Around (OWA) numbers 326 and 327. This issue was also documented in Condition Report (CR) L2001-02148.

The licensee addressed the potential causes of incorrect valve position indication by requiring operators to execute LOP-RI-03, Section E.2 to cause backflow in the RCIC system; however, if the check valves were closed but still had open indication after the backflow process, there were no compensatory actions specified beyond LOP-RI-03, Section E.2, to address the indication problem. Although the check valve position indication deficiency was added to the station OWA program after the April 2001 event, the licensee did not provide any procedural guidance to immediately dispatch an operator to perform the rod rotation evolution. During the September 2001 scram event, the inboard injection check valve (2E51-F065) showed open indication after RCIC system operation. Control room operators did not execute LOP-RI-03, Section E.2, but instead performed the rod rotation evolution which allowed the limit switches to make up and show closed indication. The correct valve position indication was restored to 2E51-F066, RCIC outboard check valve, by rotating the position indicating rod to make up the limit switches. Pending further NRC review of the adequacy and completeness of the licensee's corrective actions to thoroughly address the RCIC system check valve open indication, this is an Unresolved Item (URI 50-374/01017-01).

If proper procedural guidance was available and executed, it may have allowed the on-shift operators to make an informed decision concerning the status of the RCIC system check valves and determine any Technical Specification implications. Because control room operators failed to properly assess the RCIC system check valves indications for Technical Specification applicability, similar to the April 6, 2001, reactor scram, the NRC determined that prior corrective actions implemented in response the April event were not completed in a timely manner. This item is further documented in the annual Problem Identification and Resolution inspection report (reference NRC Inspection Report 50-373/2001-017; 50-374/2001-016).

The inspectors' discussions with the system engineer indicated that this position indicating rod-switch makeup problem was limited to Unit 2 only and had not been seen on Unit 1. This issue was documented in CR L2001-02148. A calibration for the RCIC system check valves was planned for the upcoming Unit 2 outage to correct this problem.

1R3 Condensate Storage Tank (CST)

a. Inspection Scope

The inspectors assessed the extent of damage to the CST and the conditions that led to the failure of the storage tank roof.

b. Findings

The CST was at the high end of its normal operating level at the beginning of this event. After the control room operators tripped the reactor, a main turbine trip occurred. Steam condensed in the main turbine, the moisture separator re-heater, and the feedwater heaters. As the steam condensed, high water levels occurred in the re-heater drain tank and the individual feedwater heaters. As these high water levels were reached, feed/condensate water began flowing to the main condenser. As level in the main condenser increased, the condenser hotwell reject valve opened to direct excess water into the CST. The normal condenser hotwell reject line proved to be inadequate to handle the excess condensate flowing into the hotwell and the emergency condenser hotwell reject valve opened to assist in diverting water to the CST.

Condensate Storage Tank level began to rise rapidly with the two condensate reject valves in their full open position. As the water level in CST reached the top of the tank, the increased pressure from the rising water level caused the weld that holds the top of the CST to the sides of the tank to burst in two separate locations. The two openings were approximately eighteen to twenty-four inches long with a two to four inch fishmouth opening. The control room operators were notified by the station's guard force that water was flowing from the CST. Control room operators immediately determined that condenser hotwell level was two inches below the normal setpoint and dispatched a non-licensed operator to shut the reject line manual isolation valve. Approximately 25,000 to 45,000 gallons of slightly radioactive water flowed out the CST tank cracks and the tank's 24 inch vent line before an operator could manually isolate the reject control valves. The side of the CST and the surrounding ground area were sampled for radioactive content and were found to be well below any applicable release limits. The damaged areas of the Unit 2 CST were covered with plastic and a repair package was developed to correct two damaged welds and a buckle in the side of the CST.

1R4 RCIC System Erratic Operations

a. Inspection Scope

The inspectors attempted to determine the extent of damage/potential damage to the RCIC system by a physical walk-down of the system. The inspectors reviewed the reported unstable performance (flow oscillations), control room logs, plant parameter charts, and interviewed cognizant operations and system engineering personnel.

b. Findings

RCIC System Flow Oscillations

During the April 2001, scram event, the RCIC system experienced flow oscillations while in the injection mode, shortly after manually initiating the system after the reactor scram. The corrective actions implemented by the licensee for the April 2001 oscillations, included replacing a square root converter, tightening terminal wire connections, and cleaning of contacts in the flow transmitter loop circuit. After several successful operational tests of the system, it appeared that these actions corrected the oscillations.

During the September 2001 event, the RCIC system did not experience any flow oscillations in the pressure control or injection modes of operations. The RCIC system was operated on three occasions during this event. The system automatically started in the injection mode and was restarted twice by operators to control reactor pressure.

During each operation of RCIC, the onshift operators found that the system responded appropriately and without any abnormalities. The operators stated that the only oscillations seen during the event were when the system was being realigned from the pressure control mode to the injection mode of operation. These flow oscillations were expected based on the design of the system. These expected flow oscillations were confirmed during interviews with station training personnel. The licensee documented this issue in CR L2001-02276.

Potential Damage to the RCIC System

The licensee stated that at approximately 7:30 p.m., on September 3, 2001, the operators were operating the RCIC system in the pressure mode with the pump discharging back to the CST. Subsequently, the operators shifted the RCIC system from the pressure mode to the injection mode. In performing this evolution, the operators had to open the RCIC system injection valve (2E51-F013) to the reactor vessel and close the full flow return valve (2E51-F022) to the CST. In completing these two actions, the pump attempted to discharge against the 955 psig reactor vessel pressure. This resulted in deadheading the pump and a momentary reverse flow through the RCIC system. This slammed the RCIC pump's suction check valve (2E51-F011) shut, causing a corresponding loud bang (check valve slam) and initiated a hydraulic transient (water hammer) event and caused the failure of the pump's discharge pressure gauge. After the check valve closed, the mini-flow valve (2E51-F010) automatically opened when the system pressure reached 125 psig and flow was less than 50 gallons per minute. This provided a flow path until RCIC could start injecting into the reactor vessel. The inspectors reviewed associated plant parameter response charts which confirmed the response of the RCIC system.

The control room crew received reports that a loud boom was heard on the 710' elevation of the reactor building. The reports corresponded with the time that the RCIC system was being shifted between operating modes. The licensee subsequently walked down the RCIC system on September 4, 2001, searching for signs of system abnormalities. The walk-down consisted of all RCIC piping outside the drywell with the exclusion of approximately 50 feet of underground piping from the CST and inaccessible piping in the steam tunnel. The licensee's walk-down identified that the RCIC pump discharge pressure gauge was over-ranged and bent. Also, a travel stop on a support spring can had fallen off. The licensee subsequently generated work requests to repair these two deficiencies. The licensee documented the results of the system walk-down in CR #L2001-05075. The results included the areas that were inspected, as-found system deficiencies, and the licensee's conclusion that the system remained in an operable status. The licensee initiated a procedure change request (PCR) to address RCIC system check valve slam (PCR # LOP-2001-0688).

1R5 Loss of Turbine-Driven Reactor Feed Pumps

a. Inspection Scope

The inspectors reviewed electrical prints and interviewed operators to determine the cause of the unavailability of the turbine-driven reactor feed pumps during the event.

b. Findings

Inspectors reviewed electrical prints for the feedwater control stations on the bench boards in the control room. The electrical prints showed that 241Y Bus ultimately provided power to the feedwater control stations. With the loss of voltage on 241Y Bus, a zero voltage signal went to the feedpump controllers which caused the turbine driven reactor feed pumps to run back to minimum speed. When RPV water level was restored by HPCS and RCIC, the feedwater pumps received an automatic trip signal at +55.5 inches RPV water level. The turbine driven feedpumps then became unavailable shortly after the automatic trip signal was initiated as control room operators shut the MSIVs to prevent water intrusion into the main steam lines. Since the MSIVs were not re-opened, the turbine driven reactor feed pumps were not available during the remainder of the event. The motor driven reactor feed pump was started later in the event and used to maintain RPV water level through the low-flow feedwater regulating valve. The inspectors determined that the feedwater pumps responded as designed during the event.

1R6 Assessment of Operator Actions

a. Inspection Scope

The inspectors reviewed the sequence of events, the applicable annunciator print-outs, the control room logs, and interviewed the Unit Supervisor and Nuclear Station Operator to assess the accuracy of actions taken by the operators during this event.

b. Findings

A finding of very low safety significance (Green) and an associated Non-Cited Violation (NCV) were identified by the inspectors for a failure to correctly execute an abnormal operating procedure.

Subsequent to the manual scram, RPV water level reached -50 inches, causing both reactor recirculation pumps to automatically trip. The Reactor Water Clean Up (RWCU) system also automatically isolated when RPV water level reached -50 inches. This required control room operators to enter LOA-RR-201 "Unit 2, Reactor Recirculation (RR) System Abnormal," Section B.2, 2A(2B) Recirculation Pump(s) Trip. Step 1 stated, "CHECK at least one Recirc pump operating." When the correct response was not obtained, operators used the RESPONSE NOT OBTAINED column of the procedure and executed some steps in that column, but not all required steps. Step 1.7 stated, "If RWCU is NOT running and Control Rod Drive (CRD) System is NOT required for vessel inventory SHUTDOWN CRD system." The RPV water level was being adequately maintained by a combination of HPCS, RCIC and feedwater, so the CRD system should have been shut down in accordance with the procedure. In contrast to the procedure requirement, the Operators failed to execute Step 1.7 and shut down the CRD system. The failure to shutdown the CRD System resulted in additional cold water being injected into the bottom of the vessel. The water increased the amount of the thermal stratification in the vessel. The increased thermal stratification of the vessel directly contributed to the heatup violation that occurred during the subsequent RR system recovery.

Significance Evaluation

The inspectors reviewed this issue against the guidance contained in Appendix B, "Thresholds for Documentation," of Inspection Manual Chapter (IMC) 0610*, "Power Reactor Inspection Report." The inspectors determined that with regard to the Group 1 questions in IMC 0610*, the issue if left uncorrected, would under the same conditions become a more safety significant concern. This concern was attributed to the unexpected heatup of the reactor coolant system in the reactor vessel bottom head which exceeded the 100 degree fahrenheit per hour (°F/hr) heatup rate limit specified in Technical Specification 3.4.11, "RCS [Reactor Coolant System] Pressure and Temperature (P/T) Limits", which was adversely impacted by the failure to secure the Control Rod Drive(CRD) System as directed by procedures. The failure to secure the CRD System resulted in a greater degree of thermal stratification between the upper and lower regions of the vessel. As a result, the inspectors reviewed this issue against the Group 2 questions to determine if the issue impacted one or more cornerstones. The inspectors determined that a barrier cornerstone was affected since this issue could have affected the integrity of the fuel barrier because the actual limits in the Technical Specifications were exceeded. The inspectors verified that although the limits prescribed in Technical Specification 3.4.11 were exceeded, the actual conditions had not exceeded the design thermal stress analysis and that the excessive heatup rate did not threaten the integrity of the reactor fuel. The inspectors evaluated this issue utilizing the guidance prescribed by IMC 0609, "Significance Determination Process." During that review, the inspectors determined that since only the fuel barrier cornerstone was affected, that the condition screened out as "Green." This evaluation, completed under the oversight of the RIII Senior Reactor Analyst (SRA), resulted in the classification of the issue as a "Green" finding.

Enforcement Actions

10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires that activities affecting quality be prescribed by documented procedures of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions. The failure to adequately comply with the procedure to secure the CRD system increased the thermal stratification in the vessel and resulted in excessive heatup rate during the restoration of the Reactor Recirculation (RR) System. The procedural adherence issue was an example where this criteria was not met and was a violation. However, because of the very low risk and safety-significance of the item and because the licensee has included this item in their corrective action program (Condition Report L2001-05088), this violation is being treated as a Non-Cited Violation (NCV 50-374/01-17-02(DRP))

Several other performance items were identified by the inspectors as they reviewed the operating crew's response to the loss of 241Y Bus. The following, with explanations, were identified:

1. After the reactor was manually scrammed by the Nuclear Station Operator, RPV water level decreased to -50 inches where emergency core cooling pumps automatically started to restore RPV water level. Operators did not take manual actions to control RPV water level prior to the +55.5 inch RPV water level

automatic trip setpoint for the emergency core cooling pumps. While the operators were not required procedurally to stop the pumps, they were trained in the simulator to begin taking actions to control RPV water level when it increased above +20 inches.

2. Because the operators failed to aggressively control RPV water level, there was additional water inventory in the reactor that expanded as it heated from decay heat. The expansion caused RPV water level to rise and exceed +73 inches at which time the operators were procedurally required to shut the MSIVs. The control room operators failed to re-open the MSIVs to restore the condenser as a heat sink after RPV water level returned to a normal value. This is significant in that the operators were sometimes using safety relief valves to control reactor vessel pressure. The use of safety relief valves heated the suppression pool to approximately 140°F at a time when there was only one RHR heat exchanger available to cool the suppression pool. Operators could have restored the condenser as a heat sink for core cooling and reduced the heat input to the suppression pool.

3. During the early minutes of the event, drywell cooling was de-energized and drywell pressure began to rise rapidly in response to the drywell temperature increase. Although the containment model in the control room specific simulator simulated a rise in drywell temperature and pressure, the model did not reproduce the high rate of rise in drywell pressure that occurred in the plant. Because the operators had not previously seen this rapid rise in drywell pressure as a result of a loss of drywell cooling, operators mis-diagnosed the condition as a small steam leak in the drywell. Operators later diagnosed the event correctly and restored drywell cooling. A loss of drywell cooling (loss of reactor building closed cooling water) event occurred recently at the Dresden Nuclear Station, and the control room operators were trained on the Dresden event; however, operators were still surprised at the rapid rate of change of drywell conditions during this event. The inspectors concluded that operators were not provided adequate training in the area of failure or loss of drywell cooling.

4. During the event, RCIC was used to maintain reactor pressure as well as to provide makeup to the RPV to control water level. During the transition between these two modes of operation, operators reported and documented unexpected flow oscillations. The inspectors determined that these flow oscillations should have been expected by the operators as a part of the transition between modes of operation. This was confirmed by station training department personnel. A simulator task that demonstrated the flow oscillations was used by instructors to train operating personnel in the operation of the RCIC system.

5. Control room operators were slow to initiate a shut down risk assessment, especially in light of the de-energized safety-related 241Y Bus and associated loss of Division I safety-related equipment. Four hours after the initiation of the event, the shift manager was questioned by the NRC senior resident inspector concerning a risk assessment. The shift manager immediately performed a risk assessment and determined that within the corporate guidelines provided to the station, their shutdown risk was assessed at a high "yellow" level. Although

there are no regulatory requirements, nor procedural requirements, to conduct a shutdown risk assessment within a specified time, station management concurred that the crew did not meet their expectations of timeliness with respect to initiation and completion of a shutdown risk assessment. A condition report was initiated (CR# L2001-05192) to outline management expectations for conducting shutdown risk assessments.

6. Control room operators lined up main steam line drains upstream of the MSIVs to assist in controlling reactor pressure. Because the MSIVs were shut, steam jet air ejectors were not operating and main condenser vacuum degraded. After approximately four hours, vacuum had degraded to the point where a Group I isolation was automatically initiated. The Group I isolation automatically shut the main steam line drains, removing this method of controlling reactor pressure. Keys were located for the Group I low vacuum bypass switches and the Group I low vacuum isolation was bypassed. The main steam line drains were then re-aligned to control reactor pressure. Operators logged the event and indicated that it was anticipated. The inspectors believed that the Group I isolation could have been avoided by bypassing the low vacuum MSIV closure before vacuum degraded to the isolation setpoint.

7. Operators documented several significant occurrences during the event; however, the inspectors and station personnel were unable to construct a time-line using the operator logs. Several significant items were not recorded in the operator logs and had to be retrieved from annunciator print-outs and recorders. Station management concurred that control room log-keeping did not meet station expectations.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. C. Pardee and other members of licensee management on September 19, 2001. The licensee acknowledged the findings presented. No proprietary information was identified during the inspection and exit meeting.

KEY POINTS OF CONTACT

Licensee

D. Czufin, Engineering
S. DuPont, Regulatory Assurance
D. Enright, Operations Manager
R. Gilbert, Work Management Director
G. Kaegi, Training Director
M. Okopny, Operations Supervisor
C. Pardee, Site Vice President
B. Riffer, Regulatory Assurance Manager
M. Schiavoni, Plant Manger

LIST OF ITEMS OPENED

Opened

50-374/01017-01	URI	Adequacy and completeness of the licensee's corrective actions to thoroughly address the RCIC system check valve open indication (Section 1R6)
50-374/01-17-02	NCV	Failure to correctly implement required operations procedures (Section 1R6)

Closed

None

Discussed

None

LIST OF ACRONYMS USED

ATWS	Anticipated Transient Without Scram
CR	Condition Report
CST	Condensate Storage Tank
ECCS	Emergency Core Cooling System
EOP	Emergency Operating Procedure
EDG	Emergency Diesel Generator
HPCS	High Pressure Core Spray
MDRFP	Motor Driven Reactor Feed Pump
MSIVs	Main Steam Isolation Valves
NCV	Non Cited Violation
NRC	Nuclear Regulatory Commission
NSO	Nuclear Station Operator
OWA	Operator Work Around
PCR	Procedure Change Request
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RPV	Reactor Pressure Vessel
SRV	Safety/Relief Valve
WO	Work Order

LIST OF DOCUMENTS REVIEWED

1R1 Conduct a Root Cause Evaluation on the Loss of the Unit 2 Division 1 241Y Bus

1E-2-4000PG	Relaying & Metering Diagram 4160V Switchgear 241Y
1E-2-4000PF	Relaying & Metering Diagram 4160V Switchgear 241X
Prompt Investigation	LaSalle Unit 2 Scram During Feedwater Transient Due to Undervoltage Protective Circuit Actuation on Division 1 Engineered Safety Features Bus

1R2 April 2001 Event / Licensee Corrective Actions

	Modified Test Plan for Testing JCW-1E Fuses
CR 2001-04362	Testing Method for Fuses Questioned
WO#99274401 01	Adjust Limits on 2E51-F066
CR 2001-02148	2E51-F065 and 2E51-F066 Failed to Indicate Closed after RCIC was Secured

1R4 RCIC system erratic operations

CR 2001-02276	Unit 2 Reactor Core Isolation Cooling System Oscillations During Operation Following Scram on April 6, 2001
OWA#s 326/327	Following Securing of the Reactor Core Isolation Cooling System, the F065/066 Failed to Indicate Closed
LOP-RI-03	Reactor Core Isolation Cooling System Isolation and System Shutdown Revision 13

M-147	Reactor Core Isolation Coolant System
CR 2001-05075	Loud “Booms” Heard after Unit 2 Scram

1R6 Assessment of Operator Actions

LOP-RI-03	Reactor Core Isolation Cooling System Isolation and System Shutdown, Revision 13
LOA-RR-201	Unit 2, Reactor Recirculation System Abnormal, Revision 7
	LaSalle County Technical Specifications 5.4.1