AUGMENTED INSPECTION TEAM REPORT

U. S. NUCLEAR REGULATORY COMMISSION

LASALLE UNIT 2 TURBINE AND REACTOR TRIP

AUGUST 27, 1992

INSPECTION REPORT NO. 50-374/92020(DRS)

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Number 50-374/92020(DRS) License No. NPF-18

Licensee: Commonwealth Edison Company
Opus West III
1400 Opus Place
Downers Grove, IL 60515

Facility Name: LaSalle Nuclear Power Plant, Unit 2

Inspection Conducted: August 28 through September 3, 1992

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Inspection Summary

Inspection on August 28 through September 3, 1992 (Report No. 50-374/92020(DRS))

Areas Inspected: Special Augmented Inspect. n Team (AIT) inspection conducted in response to the turbine and reactor trip at the LaSalle Nuclear Power Plant on August 27, 1992. The review included validation of the sequence-of-events, determination of the root cause for the trip and equipment failures during the event, evaluation of operator response to the event, and evaluation of the licensee's corrective actions.

Results: No violations or deviations were identified in any of the areas inspected. No significant operational safety parameters were approached or exceeded. No radiation was released. The AIT's conclusions are contained in Section 4.0 of this report.

Specific strengths noted included the following: good communications and team work between operators in the field and the control room, good prioritization of activities prevented overall actions from being diverted to individual equipment problems, and good use of procedures assisted in the prioritization and addressing of individual equipment problems. Specific weaknesses noted included the following: the high number of equipment failures related to this event, the incomplete and erroneous notification to the NRC Duty Officer, and the incorrect determination of the differential pressure across the "A" inboard MSIV prior to opening the valve.

DETAILS

1.0 Introduction

1.1 Event Summary

At 3:05 a.m. (CDT) on August 27, 1992, while Unit 2 was reducing power to 850MWe, the turbine tripped due to a thrust bearing failure alarm. The reactor subsequently scrammed automatically. Following the scram, there were the following equipment problems:

a. Water level increased in the reactor and operators were not able to trip either the "A" or "B" turbine driven reactor feedwater pump (TDFP) turbines from the control room.

b. There were problems with the position indication circuitry for the safety relief valves (SRVs) and several annunciators.

c. There were problems with reactor core isolation cooling (RCIC) starting prior to its setpoint and failing to restart manually during recovery from the event.

d. The inboard RCIC testable check valve failed to close after system shut down.

e. There was a Group I isolation during an attempt to open a main steam isolation valve (MSIV).

The operators successfully established steam flow to the condenser and the unit was placed in cold shutdown.

1.2 AIT Formation

On August 27, 1992, senior NRC managers determined that an AIT was warranted to gather information on the turbine trip, subsequent reactor scram, and equipment failures which occurred during the event. An AIT was formed consisting of the following personnel:

Team Leader: R. A. Westberg, Team Leader, Plant Systems Section, Division of Reactor Safety

Team Members: H. A. Walker, Reactor Inspector - Mechanical, Maintenance and Outages Section

J. H. Neisler, Reactor Inspector - Electrical, Plant Systems Section

M. N. Leach, Licensing Examiner, Operator
Licensing Section 1 (BWR)

M. J. Miller, Reactor Engineer,
Division of Reactor Projects

R. B. Elliott, Licensing Project Manager,
Office of Nuclear Reactor Regulation

Two members of the AIT arrived onsite during the evening of August 27, 1992. The full AIT was onsite the morning of August 28, 1992. In parallel with formation of the AIT, RIII issued a Confirmatory Action Letter (CAL) (Enclosure 3) on August 27, 1992, which confirmed certain actions in support of the team and established conditions required to be met prior to the restart of the plant.

1.3 AIT Charter

A charter was formulated for the AIT and transmitted from T. O. Martin to R. A. Westberg on August 27, 1992 (Enclosure 2) with copies to appropriate EDO, NRR, AEOD, and Region III personnel.

The AIT was terminated on September 3, 1992.

2.0 Event Description

2.1 Sequence-of-Events

At 1:15 a.m. on August 27, 1992, Unit 2 commenced a load drop from 1100 MWe to 850 MWe at 120 MWe per hour as requested by the load dispatcher. At 3:05 a.m., with load dropped to approximately 875 MWe, the main turbine tripped due to a thrust bearing failure indication. The reactor then scrammed due to the turbine trip. All turbine stop valves closed and all control rods inserted fully. RCIC automatically initiated although reactor water level never reached the RCIC initiation setpoint of level 2 (-50" below instrument zero). Due to the pressure spike caused by the closure the turbine stop valves, SRV "U" opened for approximately 10 seconds; however, the SRV fully open alarm failed to actuate in the control room. All 5 turbine bypass valves opened and steam was dumped to the main condenser.

Immediately following the scram, reactor level shrunk and motor driven feed pump (MDFP) "C" was started. When reactor level reached the level 3 setpoint (+12" above instrument zero), the RCIC injection valve opened and injected into the reactor vessel. With both main TDFPs still injecting feedwater into the reactor vessel, reactor water level recovered and swelled following the initial shrink. At 3:06 a.m., as water level rose, an attempt was made to trip the TDFPs from the control room by simultaneously tripping the pumps and closing the discharge valves. Both "A" and "B" discharge valves indicated closed after about 90 seconds, but the pumps did not trip. Reactor water level reached level 8 trip setpoint (+55"). The "C" pump tripped, the RCIC turbine steam supply valve closed, and the RCIC injection valve was closed manually. Repeated attempts to trip the TDFPs were made with no success and an equipment operator (EO) was dispatched to trip the pumps locally.

At 3:07 a.m., a drywell air temperature high alarm was received. At 3:08 a.m., the MSIVs were closed, as required by Procedure LOA-NB-10 when indicated reactor water level reached +73 inches. Reactor level indication continued to rise to +130 inches before dropping again. Between 3:09 and 3:23 a.m., 2 loops of suppression pool (SP) cooling were started in anticipation of using the SRVs for reactor pressure control.

At 3:10 a.m., TDFP "A" was locally tripped after 5-6 attempts. Similar attempts to trip TDFP "B" were unsuccessful after approximately 10 attempts. At 3:13 a.m., the nuclear station operator noticed that "B" had tripped for undetermined reasons. At 3:17 a.m., RCIC also tripped for undetermined reasons.

At 3:23 a.m., a reactor pressure high alarm was received. At 3:24 a.m., reactor pressure control was begun using SRVs "A" and "B". Again, the SRV fully open alarm did not annunciate in the control room at any time when either SRV was open. In addition, when the SRVs were closed, the control panel still showed open indications. At 3:26 a.m., a SP level high alarm was received.

At 3:36 a.m., an attempt was made to start RCIC in the pressure control mode to limit use of SRVs. The pump tripped on the first two attempts to start. At 3:40 a.m., a reactor vessel level low/pressure high alarm was received and SRV "B" was opened to lower pressure. The opening of the SRV created a swell in reactor level. At 3:41 a.m., RCIC started on the third attempt. At 3:43 a.m., the SP water bulk temperature technical limit high and SP level high alarms were received. Based on these alarms, the licensee entered LGA-03. After clearing the reactor vessel level low/pressure high alarm, SRV "B" was closed. Closure of the SRV drove level down to level 3 and caused a second scram signal. The RCIC pump automatically injected into the reactor vessel due to the Level 3 signal. Following the second scram signal, the drywell temperature high alarm was received again. The licensee entered LGA-01 due to reactor level dropping below level 3 for approximately 1.5 minutes. At 3:44 a.m., the MDFP was started to assist in recovering level. By 3:53 a.m., level was recovered, the MDFP was stopped, and RCIC was realigned to the pressure control mode.

At 4:07 a.m., the licensee notified the NRC about the turbine trip, reactor scram, and the RCIC actuation. While the notification was in progress, an operator attempted to reopen the MSIVs to allow decay heat rejection to the main condenser. As the operator opened the first of the inboard isolation valves (the outboards were already open), a Group I isolation occurred. The opening of the MSIV and the subsequent isolation caused wide swings in reactor water level. Immediately following the isolation, a level 8 alarm was received and the RCIC pump shut off. At 4:08, the RCIC turbine was tripped. By 4:09, level was low, the RCIC trip signal was reset, and the pump was restarted to assist in reactor pressure control. Reactor level had dropped to level 4 (+31.5 inches).

At 4:55 a.m., the high drywell temperature alarm had cleared. Between 4:55 and 5:01 a.m., RCIC was started and tripped twice in an attempt to close the inboard testable check valve 2E51-F066 which indicated stuck open. At 5:23 a.m., the "B" TDFP was reset and tripped successfully from the control room. At 6:10 a.m., the licensee notified the NRC with a correction of the previous 4:07 a.m. notification to include problems with TDFPs, annunciator/indication problems, and stuck open RCIC check valve. A new notification on the Group I isolation was also provided.

The event ended when Unit 2 was placed in cold shutdown on August 28, 1992.

2.2 Precursors to the Event

At the time of the event, approximately 3:05 a.m. on August 27, 1992, the only plant transient in progress was a reactor power decrease from 100% to 80% power. Prior to the event, no other plant evolutions were in progress. Based on the AIT's review of plant logs and interviews with operators, no ongoing activities which could have been precursors to the turbine trip event were identified.

2.3 Operator Response

To determine what actions the operators took in response to the event and the suitability of these actions, the AIT reviewed plant logs, the Reactor Scram Report (LGP-3-2), the Root Cause Determination of Event (LAP-200-7), appropriate plant emergency and normal operating procedures, and interviewed the operators involved in the event.

The reactor scrammed due to a main turbine trip resulting in normal shrink in reactor water level. The Unit 2 operator, center desk operator, and the extra operator performed the immediate actions following the scram and the shift engineer (SE) was called to the control room.

The "A" TDFP controller was in manual and set for six million pounds per hour flow, the "B" TDFP controller was in automatic, and the MDFP was in standby. An operator st ed the MDFP and adjusted flow to one million pounds per hour. As level began recovering, an operator initiated a trip of the "B" TDFP and closed its motor operated discharge valve. The operator noted dual indication on the valve, indicating it was closing, and that feedwater flow was decreasing. As level was above the low level point, the operator initiated a trip of the "A" TDFP and closed its motor operated discharge valve. At this point no change was noted in feed water flow. The operator reduced flow from the MDFP. As reactor water level reached Level 8 the MDFP tripped.

The SE entered the control room, immediately identified that RCIC had initiated, and directed it be shut down. The RCIC steam supply valve (FO45) closed on the Level 8 reactor water level before it could be shut down manually. The RCIC testable check valve indicated that it failed to reseat following the shut down of RCIC.

The operator's attempt to trip the TDFPs prior to reaching Level 8 reactor water level was unsuccessful. The automatic trip at Level 8 and further manual attempts, from the control room, failed to trip the TDFPs. At 73" (anticipatory value to prevent flooding the main steam lines) the SE directed the MSIVs to be closed as required by the operating procedure for high reactor water level (LOA-NB-10, Rev.3). The outboard MSIVs were closed. An EO was dispatched to trip the TDFPs locally. TDFP "A" tripped after several pulls on the manual trip lever. TDFP "B" did not trip even after 10 pulls on the manual trip lever. The TDFP "B" tripped later with the reason undetermined.

Reactor water inventory was being reduced through the reactor water cleanup system to the condenser at 150 gpm. Both loops of SP cooling were started and SRVs were used to control reactor pressure. An operator opened SRV "A" for 2-3 minutes and then opened SRV "B" to equalize heating of the suppression pool. When an operator attempted to close the "A" SRV, it still indicated open. He then tried to close "B"; however, it also indicated open. Instrument mechanics (IMs) determined from the back panel that "A" had dual indications. The closed indication light bulb on the reactor panel was burned out. Both SRVs were considered closed via decreasing tail pipe temperature, shrink and swell response of reactor water level, and reactor pressure changes. Normally other SRVs would be used in sequence to equalize heating of the suppression pool. Since two SRVs had exhibited faulty position indications, the SE did not want to chance having additional SRV indication problems. The SE directed the operators to continue using only SRV "A" and "B". Actions were taken in accordance with LOA-NB-02 "Stuck Open Relief Valve." During pressure control with the SRVs, reactor water level dropped below Level 3 one time when an SRV was closed.

Primary containment control LGA-03 was entered on high suppression pool temperature and high DW temperature. RCIC was manually started twice followed by high turbine exhaust backpressure trips. On the third attempt RCIC was started successfully, reducing the need to use the SRVs. RCIC was started several additional times to control reactor pressure with no further problems.

The MSIV inboard valves were closed and the outboards were opened in preparation for reopening the MSIV thus allowing steam to be dumped to the condenser. The operator was following operating procedure No. LOP-MS-01, "Pressurizing and Warm Up of the Main Steam Lines with the Reactor Pressurized." Upon opening the "A" MSIV, a Group I isolation occurred and rapidly closed the "A" MSIV and the outboard MSIVs. The Group I isolation was caused by an operator error - opening the MSIV with a large differential pressure (dp) across the valve (see Section 3.6 of this report for details). Following the Group I isolation due to high main steam flow, the Unit 2 foreman walked down the steam tunnel for leaks and an operator walked down the heater bay. No problems were identified. The isolation was reset, the outboards MSIVs were opened, and the bypass valves around the inboard MSIVs were opened to provide a steam path to the condenser. The "A" MSIV was opened later in the day.

Two attempts were made to seat the RCIC testable check valve. RCIC was manually started and then tripped, thus allowing the transient flow through the check valve to seat the valve. The first attempt occurred at a flow of 400 gpm which resulted in the close indication lighting momentarily (with possible dual indication). The second attempt was conducted at a flow of 500 gpm with the closed indication lasting slightly longer. An out-of-service was written to isolate the valve.

Following the event the TDFP "B" was started and tripped successfully from the control room.

During the event, equipment failures occurred which complicated the plant recovery. The specific failures are discussed in Section 3.0 of this report. Throughout the event, operators properly prioritized their actions. Operator action in response to the equipment failures was to enter the appropriate procedures for the specific systems to recover from the failures. The following procedures were entered or referenced during the event:

- LGA-01, "RPV Control"
- LGA-03, "Primary Containment Control"
- LOA-MS-02, "Recovery from Group I Isolation"
- LOA-NB-02, "Stuck Open Relief Valve"
- LOA-NB-10, "High Reactor Water Level"
- LGP-3-2, "Reactor Scram"
- LOP-MS-01, "Pressurizing and Warmup of the Main Steam Lines with the Reactor Pressurized"
- LOP-RI-02, "Starting and Operation of the Reactor Core Isolation Cooling System"

Based on discussions with plant operators and review of the LGAs, no deficiencies were identified in the effectiveness of the LGAs to guide the operators in keeping the reactor vessel and containment in a safe condition during the event.

The licensee provided two four-hour notifications to the AEOD duty officer in accordance with 10 CFR 50.72. The decision to make four-hour notifications was appropriate. Event notification work sheets were completed in accordance with procedure LZP-1310-1, Revision 1, "Notifications."

Telephone notifications to the AEOD duty officer were incomplete and partially erroneous. For example, during the 04:07 a.m. notification to the Duty Officer, the shift control room engineer (SCRE) stated that the only thing unusual or not understood was the RCIC initiation. He also stated that heat was being rejected to the condenser. Both of these statements were in error. These errors were corrected during the second notification at 06:10 a.m., which was within the required four-hour time limit. During the 06:10 a.m. notification the SCRE stated he may not have been aware of the inability to trip the TDFP's, and that they were beginning the process of rejecting heat to the main condenser.

The SCRE completed the event notification work sheet just prior to calling the Operations Center Duty Officer. During the first ENS telephone call, the "A" MSIV was being opened and the Group I isolation occurred. Since the SCRE made the phone call from the control room, he was distracted by the new alarms. Based on interviews with the AIT, the SCRE indicated he was monitoring the plant while on the telephone and was more concerned with returning his attention to the plant than with addressing the Operations Center Duty Officer questions. The SCRE was aware of the TDFP trip problems and of the indication problems with the SRVs. The SCRE also knew that decay heat was being rejected to the suppression pool by the SRVs, but he believed the "A" MSIV would be opened momentarily allowing decay heat to be rejected to the condenser. The SCRE indicated he had fulfilled the obligation of making the ENS telephone call and would provide additional information later.

In addition to the reporting discrepancies listed above, an additional scram occurred 38 minutes after the initial scram, which was not reported by a 50.72 report.

Based on review of this event, the AIT determined that operator response, with the above exceptions, was prompt, effective, and in accordance with plant procedures. The operators quickly evaluated the indications and took prompt action to place the plant in a safe condition. The operators' actions to close the MSIVs precluded flooding the main steam lines which could have been safety significant.

The AIT noted the following strengths:

- Good communications and team work between operators in the field and the control room enabled the SE to properly evaluate and deal with the event.

- Good prioritization of activities by the SE which prevented overall actions from being diverted to individual equipment problems.

- Good use of procedures assisted in the prioritization and combating of individual equipment problems.

Specific weaknesses observed by the AIT included the following:

- Incomplete and erroneous notification to the NRC Duty Officer.

- Incorrect determination of the differential pressure across the "A" inboard MSIV prior to opening the valve.

The AIT concluded that the operators safely responded to a challenging plant event and that their actions were indicative of a strong knowledge of plant systems and plant operating procedures.

2.4 Turbine Trip

The initiator of the turbine trip was a signal from the thrust bearing failure alarm. The logic is one out of one with no redundancy; therefore, once it alarmed, the main steam stop valves closed and tripped the turbine. When the AIT arrived on site, the cause of the alarm was thought to be either failure of the thrust bearing or failure of the thrust bearing wear detector.

A subsequent series of local and remote wear detector operations and turbine rotor thrust checks by the licensee ruled out failure of the thrust bearing. The results of the turbine rotor thrust bearing clearance checks indicate that the thrust bearing clearances were acceptable.

The thrust bearing wear detector is a device which continuously detects the axial position of the turbine shaft with respect to the thrust bearing casing and transmits this position signal to a pilot valve. The pilot valve, in turn, outputs to electrical pressure switches which close the main steam stop valves as soon as wear on any one of the two thrust plates exceeds approximately 0.020 to 0.30 inches.

The licensee performed a controlled disassembly of the thrust bearing assembly to investigate the possibility that something had shifted in either the thrust bearing or the wear detector causing a shift in the trip span and the subsequent trip.

This investigation indicated that a set screw had "backed off" in the gear that actuates the pilot valve pressure switch. This allowed the gear to turn on its shaft and in doing so shift the trip set point in a more conservative direction. When turbine power is reduced, the rotor shifts axially from the main thrust bearing to an auxiliary thrust bearing, by design. Thus, when this shift occurred and with the trip set point shifted, a trip occurred.

The licensee stated that consultation with the manufacturer determined that the root cause of the set screw backing off was that it was supposed to be "staked" (to prevent movement) during assembly at the factory and it was not.

3.0 Equipment Failures

3.1 TDFP Failure to Trip; Automatic, Remote, and Local.

The TDFPs are single stage, dual suction, horizontal centrifugal pumps driven by steam turbines. The turbines are horizontally mounted, non-condensing impulse turbines which are connected to the feedwater pump through flexible couplings. Turbine speed is varied by the feedwater control system to control the amount of feedwater pump output. The feedwater pumps are shut down by tripping the turbines. A control oil system is used to close the turbine stop valve and shut down the turbine. Control oil, as well as bearing lube oil for the TDFPs, is supplied from the main turbine lube oil system at the discharge of the lube oil cooler.

During the event, both TDFPs failed to trip electrically on several attempts from the control room. Both pumps also failed to trip automatically on a level 8 signal. Several attempts were also made to trip both pumps locally utilizing the mechanical trip handles. After the fifth or sixth attempt, the "A" TDFP tripped; however, "B" TDFP did not trip after 10 attempts. Following the 10 attempts, a dual indication was received in the control room and then the "B" TDFP tripped. The trip was verified locally.

The licensee's investigation revealed that the TDFPs had received a legitimate automatic trip signal but did not trip. The licensee also tested the manual remote trip from the control room to the control solenoid. The AIT witnessed the licensee's test of the local manual trip. All circuits and the solenoid were found to be operable.

No work had been performed on the TDFPs or the turbine trip controls since the Unit 2 refueling outage which ended in May. During the refueling outage the turbine trip valves were disassembled and reworked. No significant problems were noted during this work and no problems were noted during subsequent testing and operations.

During the review of TDFP records, problems did not appear to be excessive and no previous incidents of the complete inability to shut down the TDFPs were noted. No repetitive problems of any type were noted.

Troubleshooting and corrective action investigation of the Unit 2 TDFPs was started immediately. Prior to the inspection, electrical testing was performed on the "B" TDFP. While on the turning gear, the turbine was successfully tripped and reset several times from the control room. Electrical testing of "A" TDFP and the disassembly and inspection of both "A" and "B" TDFPs was delayed until the start of the inspection. Action plans directed completing work on "A" TDFP, including reassembly and testing, prior to disassembly and inspection of the "B" TDFP. The final assembly and testing of the "A" TDFP and most troubleshooting and corrective action investigation of "B" TDFP was completed after the AIT had left the plant. Actions taken and problems noted in these areas were provided to the NRC by licensee personnel by telephone.

A complete electrical and mechanical inspection was performed on the trip mechanism and associated components of both TDFPs. The components were disassembled and inspected. The inspection included a visual check of the complete mechanism for scoring of pistons and cylinders, burrs and other mechanical damage or irregularities. Clearances were checked and logged and the control oil was checked for contamination. The results of these inspections follows:

(a) The "A" electrical trip solenoid, SV-12, was disassembled and inspected. No burrs or scores were noted in the cylinder or piston and no foreign particles were found in the solenoid. During a mechanical inspection of parts, the runout measurements of the solenoid shaft exceeded tolerances. The solenoid was replaced; however, the solenoid had been previously tested and had operated properly. Therefore, the out-of-tolerance condition did not appear to be a contributor to the failure to trip problem. The solenoid tested satisfactory during subsequent testing.

The "B" electrical trip solenoid, SV-12, was disassembled and inspected. No burrs or scores were noted in the cylinder or piston and no particles were found. No problems of any type were noted with this solenoid and the solenoid tested satisfactory during subsequent testing.

(b) Prior to component removal, external . nkages were inspected and all appeared to be normal with no evidence of wear or binding on both TDFPs.

(c) Two samples were taken of the control oil from both TDFPs. In both cases, one sample, taken from the standard area, felt clean and appeared to be clean visually. The second sample, taken from the internal oil ports of the pump and governor assembly in the front standard area, felt gritty to the touch and was visibly dirty with multiple suspended particles. Most of the particles were small, but some were up to one 1/4" in length. The analysis of the oil samples and the particles did not indicate any unusual material or conditions. e dirty oil problem was thought to be a buildup and accumulation of crud in the low flow areas of the standard ports over a period of time. These ports were thoroughly flushed before the trip mechanism was reassembled. Licensee personnel indicated that flushing of these ports will be included in normal preventive maintenance of these trip mechanisms at each refueling outage.

(d) During disassembly, some particles were found on the end of the "A" hydraulic dump valve. There was no scoring or evidence that these particles caused any binding or problems with the valve. The particles appeared to be some kind of sealant. The particles were sent out to be analyzed.

(e) During the mechanical inspection of the "A" trip assembly, slight scoring was noted inside the two cylinders. A run out check of the trip dump valve shaft was performed to determine shaft bending and concentricity. The measurements significantly exceeded required tolerances and the trip dump valve shaft was replaced. The cylinder scoring was not considered serious enough to affect the operation of the trip mechanism. Other dimensional checks and clearances were within the vendor specified tolerances.

(f) During the mechanical inspection of the "B" trip assembly, an "O" ring, not shown on the vendor drawings, was found installed on the trip dump valve shaft. This "O" ring provided a small increase in the shaft friction. A run out check of the trip dump valve shaft was performed to determine shaft bending and concentricity. Run out measurements were within specified tolerances. Other dimensional checks and clearances were within vendor specified tolerances. Neither the licensee nor the manufacturer (GE) had any record of ever modifying the trip valve shaft bushing to accept an "O" ring.

Based on the results of the disassembly and inspection and consultation with vendor representatives, licensee personnel concluded that the most probable cause of the "A" TDFP failure to trip was excessive friction on the trip dump valve shaft due to contamination of the control oil and the out-of-tolerance trip dump valve shaft. The combination of these two problems resulted in a failure of the trip dump valve to reposition due to shaft binding. The trip mechanism was reassembled with a new trip dump valve shaft. The cause of the dirty control oil and the shaft out-of-tolerance condition had not been determined. After reassembly, the trip mechanism was successfully tested several times and the pump was declared operable.

Licensee personnel concluded that the most probably cause of the failure of the "B" TDFP to trip was excessive friction on the trip dump valve shaft due to contamination of the control oil and the "non-specified" "O" ring. The combination of these two problems resulted in a failure of the trip dump valve to reposition due to binding of the shaft. The trip mechanism was reassembled without the "O" ring. The cause of the dirty control oil and the installation of non-required parts in the trip dump valve had not been determined. After reassembly, the trip mechanism was successfully tested several times. Licensee personnel stated that, prior to pump operability, a partial disassembly of the front standard area would be made to verify that the control oil ports were clean.

On September 1, 1992, both Unit 1 TDFPs were tripped electrically from the control room and both pumps tripped properly.

3.2 SRV Failure to Reposition and/or SRV Position Indicating Circuitry Failure

Subsequent to the reactor scram, the operators were using SRVs "A" and "B" for pressure control. When the operators closed the valves, neither valve received a closed indication. A check of SRV discharge pipe temperatures indicated that the valves had closed.

The licensee's investigation determined that the problem was in the SRV position indication circuitry. Inspection of the linear variable differential transformers (LVDTs) revealed that the LVDT on SRV "B" was physically stuck in the intermediate position, approximately 5/8" from full extension. When the LVDT was disassembled, evidence of corrosion or fretting (motion induced wear or corrosion) between the stainless steel pin and the brass guide was found. Analysis of this area by the licensee's material analysis department determined that it was, in fact, fretting.

The licensee replaced the LVDTs on valves "A" and "B". Five other SRVs were inspected during the AIT and fretting was found on one other valve which was subsequently replaced. All remaining SRVs were inspected, cleaned, and tested prior to restart of the unit. All LVDTs on the automatic depressurization system were replaced with new units. In addition, the licensee committed to perodically inspect the LVDT position indicators.

The AIT determined that the problem with the LVDTs was generic to Unit 2 only as the other unit employs sealed magnetic reed switches in the SRV position indicating circuitry instead of LVDTs.

During the event and also during the recovery, no SRV fully open annunciator was received. When the AIT first arrived onsite, this was attributed to a failed circuit board. When the circuit board was tested in the shop, it tested satisfactorily. The licensee's investigation indicated that the corrosion found on the circuit board's terminals was the root cause of failure.

3.3 RCIC Testable Check Valve Failure

The RCIC system contains two identical six inch tilting disc check valves, which are air operated for testing. The valves, manufactured by Anchor/Darling Valve Company, are used for containment isolation and are in series with one located inside the drywell (inboard) and one located just outside the drywell (outboard).

After shutdown of the RCIC system during the event, control room panel lights indicated that the inboard check valve, 2E51-F066-V25, failed to reseat. The outboard valve, 2E51-F065-V25, appeared to operate properly.

No work had been performed on the RCIC testable check valves and the associated limit switches since the Unit 2 refueling outage which ended in May; however, during the refueling outage the limit switches were changed from "Snap Lock" to "Micro Switch" switches. The modification was completed satisfactorily and no problems were noted with the valve or the limit switches during testing and subsequent operations.

During the review of the testable check valve maintenance records, valve and associated limit switch problems did not appear to be excessive and no previous incidents of the failure to fully close were noted. In addition, no repetitive problems of any type were noted with the valves.

During a visual inspection of the valve after the incident, valve 2E51-F066-V25 appeared to be closed and the problem was thought to be the valve limit switches which indicate valve position. Subsequent testing; however, indicated that the valve was binding and the weight of the disc was not sufficient to close the valve. The valve could be closed by applying a small rotating force by hand. Based on the small amount of force required for closing, licensee personnel stated the valve would have closed properly if dp had existed across the valve. The problem was thought to be excessive packing friction. The valve was disassembled, valve packing was removed and the internal parts were inspected. Slight scoring of the valve shaft was noted. The shaft was polished to smooth the scoring and live loaded packing was installed to reduce packing friction. After reassembly, the valve was tested and operated properly.

Based on the results of the disassembly and inspection, licensee personnel concluded that the most probably cause of the failure of the RCIC testable check valve to fully close was excessive packing friction and scoring on the indicator hinge pin shaft. The cause for the excessive packing friction and the shaft scoring were not determined; however, the change to live loaded packing should improve the packing friction problem.

Although outboard check valve, 2E51-F065-V25, appeared to operate properly during the event, inspection and testing was also conducted on this valve. During the valve inspection, the actuating arms for the limit switches did not appear to be properly aligned with the limit switch cams mounted on the valve shaft. Although the valve position lights were indicating properly, the limit switch actuating arms were not riding on the designed cam surface for limit switch actuation. The problem with limit switch and cam alignment was corrected. This problem was apparently caused by inadequate alignment of the two parts during the change out of the limit switch during the last refueling outage. During valve testing, the valve operated properly.

3.4 Reactor Protection System (RPS) "First Out" Red Annunciator

Following the scram, the operators noticed that no "first out" annunciator (the alarm which annunciates first when several annunciators alarm almost simultaneously) had occurred on Panel No. 2H13-P603, RPS first out panel. The first out is displayed in red to differentiate it from other alarms.

The licensee developed a special test to test all the first out annunciators. The test identified two non functioning red lamps in the "turbine stop valve not fully open" alarm window. This alarm was the first RPS alarm to annunciate; however, since both first out lamps were burned out, it was not visible to the operators. Both red lamps were replaced and the annunciator window functioned properly. All other windows were operable. Two other windows were found with one lamp burned out. These lamps were replaced and the windows retested satisfactorily.

Analysis of the sequence-of-events recorder revealed two alarms out of sequence. The recorder listed the EHC master turbine trip as the first out; however, the trust bearing failure turbine trip should have been the first out. This was due to the trip alarm logic. Both alarms came from relays energized from a common turbine master trip bus. Therefore, once the turbine trip bus energized, it became a relay race between the two relays as to which alarm was first. The difference between the alarms on the sequence-of-events was one millisecond.

The licensee had previously developed electrical maintenance surveillance No. LES-AN-101, "Reactor Protection and Turbine First Out Annunciator Functional Test," (nontechnical specification, nonsafety related) in November of 1988. The surveillance procedure had not been entered in the LaSalle tracking program and had not been performed. During the AIT, the procedure was entered into the tracking program for continued use and then it was used to test the Unit 1 first out annunciators with acceptable results.

3.5 Unexpected RCIC Initiation and Trips

During the event, RCIC initiated prior to its set point and tripped unexpectedly during several starting operations.

The initiation of RCIC prior to its setpoint is a recognized phenomenon at the LaSalle plant and has been the subject of several deviation reports previously. Following closure of the turbine stop valves, there is a resulting pressure wave which is transmitted through the steam lines to the steam dome and causes pressure spikes in the reference legs of various reactor vessel level instruments. This pressure wave causes spikes below the level 2 set point of very short duration, as seen in the wide range level instruments. Such spiking does not indicate an actual low level condition, and is most apparent in level applications using Rosemount Model 1153 and 1154 series transmitters.

During two manual attempts to start RCIC, it tripped on high exhaust pressure. The licensee and the turbine manufacturer identified the most probable cause of the RCIC trips as water in steam inlet lines. When the TDFPs failed to trip, some water reached the inlet to the RCIC steam system which takes its supply from the bottom of the main steam line. This water passed through the RCIC turbine and flashed to steam in the exhaust line resulting in increased exhaust pressure which tripped the RCIC turbine on 25 psig exhaust back pressure. The licensee subsequently walked down the RCIC steam inlet piping and determined that no damage had occurred.

3.6 Group I Isolation

The Group I isolation that occurred during the attempt to open an inboard MSIV with the outboard MSIVs open was caused by operator error. The operator was following operating procedure, "Pressurizing and Warm Up of the Main Steam Lines with the Reactor Pressurized," (LOP-MS-01, Rev. 11), which required the dp across the inboard MSIVs to be equalized to less than 200 psig. The operator in the control room had no dp gage to determine the value. The dp was determined by looking at reactor wide range pressure on the reactor panel and main steam line pressure on the turbine panel. The turbine panel has similar instrument gages with two main steam line pressure gages, two electro-hydraulic control pressure set gages, and one steam chest pressure gage. The gages are located in the same general area and all have the same indicating range. The operator stated he may have looked at the wrong gage, causing him to believe the dp was within the required 200 psig. Upon opening the "A" MSIV, the noise from steam flow was much greater than was expected and the operator immediately realized his error. The Group I isolation on high steam flow rapidly closed the "A" MSIV and the outboard MSIVs. The computer data indicated the actual dp across the inboard "A" MSIV was 760 psig.

The AIT determined that this appeared to be an isolated incident. The procedure for opening MSIVs is part of the operator training program and all operators h-d been train on the procedure.

3.7 Other Failures That Could Have Affected Operators Response to Event

High drywell (DW) temperature identified on the safety parameter display system (SPDS) and confirmed by one of the safety related DW temperature instrument was an indirect result of the scram. Primary containment control LGA-03 was entered on high suppression pool temperature and the high DW temperature. DW temperature was 140° F as displayed by SPDS with a valid data indication. The safety related instrument indicated 136° F The other indications were 115-120° F. The entry condition was 135° F. The SPDS auctioneers between four signals to indicate the highest valid signal. The single high value appears to be due to the temperature element's proximity to the control rod drives (CRD) scram discharge pipes. Following the scram, the hot water in the CRDs passes through these pipes. The same high drywell temperature transient was noted 38 minutes after the initial scram when a second automatic scram occurred due to reactor water Low Level.

The licensee is continuing to monitor the drywell temperature sensors and make repairs or modification as required. This item will be pursued further by the resident inspectors during the next reporting cycle.

4.0 Safety Significance and Conclusions

The AIT determined that the safety significance of the event was minimal. No significant operational safety parameters were approached or exceeded. There was no release of radiation. The NRC [illegible] concerned about the number of equipment failures that occurred subsequent to the event; however, no common factors were identified.

The operators safely responded to a challenging plant event and their actions were indicative of a strong knowledge of plant systems and procedures. Licensee recovery from this event was thorough and corrective actions were generally good.

The AIT concluded the following:

- The root cause of the turbine trip was a shift of the main thrust bearing wear detector trip span due to an assembly error. A set screw backed off because it was not "staked" (pinned to prevent movement) during assembly at the factory.

- The most probable cause of the failure of the TDFPs to trip was failure of the oil dump valves to drain due to contaminated oil.

- The most probable cause of the failure of the RCIC testable check valve to seat was friction in the valve packing and a scored shaft.

- The most probable cause of the RCIC trips was water in the inlet steam lines which caused a back pressure trip.

- The root cause of the Group I isolation was incorrect determination of the differential pressure across the "A" inboard MSIV prior to opening the valve due to personal error.

* The root cause of the "first out" red annunciation failure was due to burned out lamps and the root cause of the SRV fully open annunciator failure was corrosion on the terminals of a circuit board.

5.0 Exit Meeting

The team met with licensee representatives (denoted in Enclosure 4) on September 3, 1992, and summarized the purpose, AIT charter items, and findings of the inspection. The team discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the team during the inspection. The licensee did not identify any such documents or processes as proprietary.

ENCLOSURE 2

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

AUG 27 1992

MEMORANDUM FOR: R. A. Westberg, Team Leader, LaSalle Augmented Inspection Team (AIT)

FROM: T. O. Martin, Deputy Director, Division of Reactor Safety

SUBJECT: AIT CHARTER-LASALLE UNIT 2 TURBINE/REACTOR TRIP

An Augmented Inspection Team (AIT) is being dispatched to the LaSalle County Station in accordance with NRC Manual Chapter 0325. The AIT is being sent due to the significance and apparently complicated system interaction which occurred during the Turbine/Reactor trip on August 27, 1992, (i.e., both turbine driven main feedwater pump automatic and manual trips failed).

Enclosed for your implementation is the final Charter to evaluate the events associated with the August 27, 1992 LaSalle Unit 2 Turbine/Reactor Trip. This Charter was prepared in accordance with the NRC Incident Investigation Manual and the April 18, 1992, Manual Chapter 0325 AIT implementing procedure.

The AITs objectives are:

1) Conduct a timely, thorough, and systematic inspection related to this event.

2) Assess the safety significance of the event and communicate to Regional and Headquarters management the facts and safety concerns related to the event such that appropriate followup actions can be taken.

3) Collect, analyze, and document factual information and evidence sufficient to determine the cause(s), conditions, and circumstances pertaining to the event.

If you have any questions regarding these objectives or the enclosed Charter, please do not hesitate to contact either Hub Miller or myself.

T. O. Martin

T. O. Martin, Deputy Director
Division of Reactor Safety

Enclosure: AIT Charter

See Attached Distribution

Distribution

cc w/enclosure:
A. B. Davis, RIII
C. J. Paperiello, RIII
F. J. Miraglia, NRR
J. G. Partlow, NRR
C. E. Rossi, NRR
R. Barrett, NRR
D. Ross, AEOD
J. A. Zwolinski, NRR
G. E. Grant, EDO
D. Hills, SRI
E. Leeds, NRR
B. Siegel, NRR

LaSalle Unit 2 Scram with Equipment Failures
Augmented Inspection Team (AIT) Charter

Under your direction, your team is to perform an inspection to accomplish the following:

1. Determine and validate the sequence of events associated with the August 27, 1992, LaSalle Unit 2 scram and equipment failures.

2. Determine the cause of the August 27, 1992, Turbine Trip and Reactor Scram.

3. Evaluate and identify the root cause of equipment failures at LaSalle Unit 2 that were identified on August 27, 1992, including:

   a. Turbine Driven Main Feedwater Pump (TDMFP) failure to trip; automatic, remote, and local.

   b. Two Safety Relief Valves (SRVs) failure to reposition and/or SRV position indicating circuitry failure.

   c. Reactor Core Isolation Cooling (RCIC) testable check valve failure.

   d. Reactor Protection System first out "red" annunciator failure.

   e. RCIC failure to properly start after high level trip.

   f. Group 1 isolation during attempts to equalize pressure across the MSIVs.

4. Evaluate Unit 2 findings for Unit 1 applicability.

5. Identify, evaluate, and determine the root cause of any other significant equipment problems with safety-related or balance of plant equipment that could have interfered with the operators ability to safety operate the plant.

6. Determine if any component failures were repetitive.

7. Evaluate the licensee's effectiveness at evaluating the events. Oversee troubleshooting, testing, and analysis of quarantined equipment including, TDRFP, SRV's, and RCIC testable check valve.

8. Interview plant personnel involved in the scram and the equipment failures to determine if personnel actions and procedural guidance were adequate.

9. Evaluate licensee managerial performance related to this event including shift supervision, management response, and maintenance supervision of activities involving failed components.

10. Evaluate completeness and accuracy of licensee's 10 CFR 50.72 report.

ENCLOSURE 3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

AUG 2 7 1992

CONFIRMATORY ACTION LETTER

Docket No. 50-374 CAL-RIII-92-011

Commonwealth Edison Company
ATTN: Mr. Cordell Reed
Senior Vice President
Opus West III
1400 Opus Place
Downers Grove, IL 60515

Dear Mr. Reed:

This confirms the conversation on August 27, 1992, between Mr. Thomas O. Martin of my staff and Mr. D. Galle of your staff related to the scram and equipment failures at LaSalle Unit 2 which occurred on August 27, 1992. With respect to the LaSalle Unit 2 matters discussed, we understand that you will perform the following actions:

1. Conduct an investigation to determine the cause of:

   a. The failure of the Main Feedwater Pumps (MFP) to trip.

   b. The failure of the Safety Relief Valves (SRV) to reposition and/or failure of the SRV indicating circuitry.

   c. The failure of the Reactor Core Isolation Cooling (RCIC) testable check valves or its indicating circuitry.

   d. Failure of the first out "Red" annunciator.

   e. An unexpected trip of RCIC hile in the pressure control mode.

   f. The Group 1 isolation during attempts to equalize pressure across the Main Steam Isolation Valves (MSIV).

   g. The turbine/reactor trip.

2. Place the MFP trip circuitry and mechanical actuator, the SRVs and their circuitry operated during the event, and the RCIC testable check valve and its circuitry in quarantine until released by the NRC's Augmented Inspection Team (AIT).

3. Maintain documentary evidence of your investigation effort and make this available to the AIT.

4. Evaluate these most recent equipment failures and operator actions in light of past equipment failures and operator performance to determine if additional actions are necessary.

5. Evaluate the applicability of the equipment failures associated with the August 27, 1992 event to LaSalle, Unit 1.

6. Provide within 30 days to NRC Region III a documented evaluation of the above issues including corrective actions you have taken or plan to take.

We further understand that reactor startup (power operation) will not occur until you have informed the Regional Administrator or his designee of the results of your investigation and corrective actions.

None of the actions specified herein should be construed to take precedence over actions which you feel necessary to ensure plant and personnel safety.

If your understanding differs from that set forth above, please call me immediately. Issuance of this Confirmatory Action Letter does not preclude issuance of an Order formalizing the above commitments or requiring other actions on the part of Commonwealth Edison Company. Nor does it preclude NRC from taking enforcement action for violations of NRC requirements that may have prompted the issuance of this letter.

Sincerely,

Carl J Paperiello

A. Bert Davis
Regional Administrator

See Attached Distribution

cc:
D. Galle, Vice President, BWR
Operations
T. Kovach, Nuclear Licensing
Manager
G. J. Diederich, Station Manager
DCD/DCB (RIDS)
OC/LFDCB
Resident Inspectors, LaSalle,
Dresden, Quad Cities
R. Hubbard
J. W. McCaffrey, Chief, Public
Utilities Division
Licensing Project Manager, NRR
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J. R. Goldberg, OGC
R. J. Barrett, NRR
R. J. Strasma, RIII
R. C. Knop, RIII
R. A. Westberg, RIII

Enclosure 4

Personnel Contacted

Commonwealth Edison Company (CECo)

D. Galle, Vice President, BWR Operations
G. J. Diedrich, Station Manager
C. E. Sargent, BWR N.O
J. Kocek, Nuclear Safety Engineer
D. Bowman, Quality Verification Engineer
H. J. Hentschel, Assistant Superintendent of Operations
R. W. Tomala, Nuclear Engineer, BWR Systems
R. M. Raglan, BWR Nuclear Operations
R. McConnaughay, Operations
J. D. Williams, Design Supervisor, NED
J. R. Bell, Staff Supervisor, GAS
S. Kleinhardt, Technical Staff, EHC System Engineer
M. Tennyson, RCIC System Engineer
M. Craig, Master Instrument Mechanic
M. Smith, Technical Staff
R. Schields, Technical Staff Supervisor
M. G. Santic, Assistant Superintendent of Maintenance
J. Gieseker, Project Manager, ENC
D. Carlson, Regulatory Assurance/NRC Coordinator
J. Lockwood, Regulatory Assurance Administrator, NLD
W. R. Huntington, Technical Superintendent
L. R. Blunk, Licensed Training
M. W. McLain, Technical Staff
D. C. Schafer, Technical Staff
J. Bruciak, Maintenance Staff
R. Crawford, Master Electrician

State of Illinois

J. Roman, Resident Inspector

U. S. Nuclear Regulatory Commission (NRC)

D. E. Hills, Senior Resident Inspector
C. Phillips, Resident Inspector

Enclosure 5

Sequence-of-Events

Thursday, August 27, 1992 (all times are a.m.)

1:15	Unit 2 started load drop from 1100 to 850 MWe at 120 MWe/hr per the load dispatcher using recirculation flow controller.
3:05:29	Turbine trip - turbine master trip alarm in control room and thrust bearing wear detector alarm first out on EHC panel. All stop valves closed and reactor automatically scrammed. Reactor recirculation pumps switched to slow speed. First out annunciator for scram did not work on 603 panel. All five turbine bypass valves opened.
3:05:30	Reactor pressure high alarm. Pressure > 1020 psig.
3:05:31	Reactor core isolation cooling (RCIC) system initiated spuriously. Setpoint is level 2 (-50 inches below instrument zero). Level did not reach that low.
3:05:32	Safety relief valve (SRV) U automatically opened to control reactor pressure. Setpoint = 1076 psig.
3:05:34	Mode switch was manually set to shutdown.
3:05:36	The A turbine driven reactor feedpump (TDFP) received trip signal. Trip signal then reset. Pump did not trip.
3:05:37	Level shrunk due to closure of main turbine stop valves. An operator started C motor driven reactor feed pump (MDFP) in accordance with station procedures.
3:05:39	Reactor level low = 11.9 inches. Level 3 low level (+12 inches above instrument zero).
3:05:43	SRV U closed. Reactor pressure < 1020 psig. Reactor pressure high alarm cleared.
3:05:55	Turbine bypass valves closed to control pressure at setpoint.
3:05:59	Reactor level = 27 inches.

3:06:02 Reactor level swelled following initial shrink. Both TDFPs were still injecting into the vessel at this point. An operator activated the manual trip of the B TDFP's while simultaneously initiating closure of the related discharge valve. The pump did not trip and the valve requires significant time to completely close. An equipment operator (EO) was dispatched to locally trip the TDFPs.

3:06:05 RCIC injection valve 2E51-F013 opened in response to level 3 low reactor water level signal. (See 3:05:39). RCIC was injecting into the reactor vessel at this point.

3:06:09 ADS or SRV leakage alarm apparently in response to the SRV which had opened following the trip.

3:06:28 Reactor vessel level 8 alarms started coming in (high water level, +55.5 inches above instrument zero).

3:06:30 MDFP C tripped on level 8 signal. TDFPs A and B also received level 8 trip signals but did not trip.

3:06:31 RCIC water level high signal to RCIC pump.

3:06:32 The operator activated the manual trip of TDFP A and simultaneously initiated the discharge valve closure. The pump did not trip.

3:06:42 The operator manually closed the RCIC injection valve 2E51-F013. At the same time, RCIC shuts off due to the Level 8 signal. The RCIC turbine steam supply valve 2E51-F045 and the outboard testable check valve 2E51-F065 closed. The inboard testable check valve 2E51-F066 did not close.

3:06:59 Reactor level = 82 inches.

3:07:09 DW air temp high alarm. This alarm is based on one signal only (auctioneered, valid high). Setpoint = 135 °F.

3:07:18 The B TDFP discharge valve went completely closed.

3:07:48 The A TDFP discharge valve went completely closed.

3:07:55 The operator manually started closing the main steam isolation valves (MSIVs) when reactor level exceeded 73 inches in accordance with station procedure LOA-NB-10.

3:08:13 The last of outboard MSIVs went completely closed. Maximum indicated reactor water level observed by the shift engineer was +130 inches.

3:09:59 The operators started 2 loops of suppression pool cooling between 3:09 and 3:23 in anticipation of opening SRVs for reactor pressure control. The operator started the B RHR pump.

3:09:04 RHR pump B discharge pressure low alarm.

3:09:05 RHR B pump reset.

3:10:20 Drywell temperature = 135.1 °F. High drywell temperature setpoint = 135.0 °F.

3:10:35 The EO attempted local trips of the TDFPs. The A TDFP was tripped after approximately 5 to 6 attempts. Approximately 10 attempts were made to trip the B TDFP pump. The B pump did not trip at this time.

3:12:57 B TDFP trip alarm. Approximately 2 minutes after the EO had been unsuccessful in tripping the B TDFP, it tripped on its own for no apparent reason.

3:16:04 ADS or SRV leakage alarm normal.

3:17:03 RCIC turbine tripped. Cause of trip is unknown. The pump was not running at the time.

3:17:10 RCIC turbine reset.

3:23:22 An operator started RHR A pump for suppression pool cooling.

3:23:53 Reactor vessel pressure high alarm. Reactor pressure > 1020 psig.

3:24:17	The operator manually opened SRV A to control reactor pressure. The SRV fully open alarm did not illuminate. During the licensee debrief, the operators could not recall anything about this alarm during event. The operators were also unaware that SRV U had opened immediately following the trip indicating that this alarm had not actuated at that time either.
3:24:27	ADS or SRV leakage alarm due to open SRV.
3:24:50	Reactor pressure normal.
3:26:26	Div I LO-LO set point seal in alarm (went back to normal at 3:27:48). SRV B manually opened.
3:26:27	SRV A manually closed. Open indication remained. SRV A also showed open on SPDS.
3:26:40	Suppression chamber level high alarm. SE log and Unit 2 log indicate entrance into LGA-03 on suppression pool temperature and level at 3:50.
3:27:26	SRV B manually closed. Open indication remained. Also showed open on SPDS.
3:29:12	SRV B manually opened The operator opened and closed the SRVs several times in an attempt to get a closed indication on the control room panel. He was not successful in getting a closed indication.
3:29:14	SRV B manually closed.
3:29:15	SRV A manually opened.
3:29:16	SRV B manually closed. Reactor vessel level on SPDS = 55 inches.
3:29:44	Reactor vessel level = 63 inches on wide range.
3:33:07	SRV A manually opened.
3:33:19	SRV B manually opened.
3:33:43	SRV A manually closed.
3:33:54	SRV B manually closed.

3:33:59 Reactor vessel level on SPDS = 52 inches. Operators said they pulled fuses. SE log indicates that this was done at 3:27 and noted that the operator believed the SRVs were closed based on tailpipe temperatures and reactor pressure.

3:34:21 RCIC Reactor vessel water level normal.

3:36 The operator attempted to start the RCIC pump for pressure control since water level was below RCIC trip setpoint. The system was configured to take suction from and discharge to the condensate storage tank.

3:36:17 RCIC turbine exhaust pressure high alarm.

3:36:18 RCIC turbine trip. RCIC tripped on high exhaust pressure on first attempt to manually start for pressure control.

3:37:49 RCIC turbine reset by the operator.

3:38:29 Reactor water level 7 normal.

3:38:52 RCIC turbine exhaust pressure high. RCIC turbine tripped on second attempt by the operator to manually start for pressure control. RCIC drain pot level high alarm.

3:39:31 Reactor vessel pressure high alarm. Reactor pressure > 1020 psig.

3:40:04 RCIC turbine was reset by the operator.

3:40:24 Reactor vessel level low/pressure high alarm.

3:40:33 Reactor vessel pressure high alarm.

3:40:46 SRV B manually opened following reactor high pressure alarms.

3:41:02 RCIC pump discharge flow normal.

3:41:03 Reactor vessel level high alarm (Level 8).

3:41:29 Reactor pressure normal.

3:41:40 Reactor vessel level normal.

3:42:38	Suppression pool water bulk temperature technical limit high alarm. (Setpoint = 105°F)
3:42:59	Suppression pool level high alarm (0.3 feet).
3:43*	SRV B manually closed.
3:43:01	Reactor vessel level 4 low alarm.
3:43:39	Low reactor water level division B2 (Level 3). Back-up scram signal received. Per SE log LGA-01 was entered when level dropped below 12.5 inches while cycling the SRVs. U2 log indicated Level 3 scram occurred when SRV B was closed and LGA-01 was entered for 1.5 min.
3:43:40	ADS or SRV leakage normal.
3:43:41	B diesel generator engine received a trip signal.
3:43:46	ADS or SRV leakage alarm. Alarm signalled and then went back to normal.
3:43:53	RCIC automatically injected into the reactor vessel in response to the level 3 signal.
3:44:09	MDFP was started by the Operator.
3:45	Drywell temperature high alarm.
3:45:52	Reactor water level on SPDS = 5 inches.
3:45:55	Drywell temperature = 135.3 °F.
3:46:11	Reactor water level 3 confirmed normal.
3:49:44	Back-up scram was reset.
3:51:28	RCIC injection was terminated.
3:52:42	MDFP was shut off.
4:00	Offgas mechanical vacuum pump was started by the operator to maintain vacuum.
4:06:32	Reactor pressure = 846 psig.

4:07 Licensee makes first of two 50.72 notifications to the NRC. The first call described the turbine trip/reactor trip and the spurious actuation of the RCIC system.

4:07:30 The operator attempted to reopen the MSIV's to allow decay heat rejection to the main condenser. The operator failed to properly equalize pressure to less than 200 psid on both sides of MSIV 2B21-F022A prior to attempting to open it. When the operator attempted to open the valve, the actual differential pressure across the valve was 760 psid which led to a high steam flow condition causing a Group I isolation and large swings in reactor level.

4:07:32 Reactor vessel water level high alarm. (Level 8). MDFP C tripped on level 8 signal.

4:07:34 Group I isolation on high steam flow.

4:07:44 RCIC shuts down due to level 8 signal. Drywell temperature = 133.6.

4:07:59 Reactor water level 7 normal.

4:08:19 Reactor pressure = 846 psig.

4:08:22 RCIC turbine tripped by the operator.

4:08:27 Reactor water level 4 low.

4:09:34 RCIC turbine reset.

4:10:42 MDFP C and RCIC pump were restarted by the operator for reactor pressure and level control.

4:12:07 RCIC pump discharge flow normal.

4:57:59 RCIC turbine trip. The operator tripped and restarted RCIC two times in attempt to close check valve 2E51-F066 by manual injection of RCIC water. Both attempts failed to close valve.

4:59:15 RCIC turbine reset.

5:01:01 RCIC turbine trip.

5:23 Operators reset and tripped B TDFP successfully from control room.

5:25 SE and Unit 2 logs indicate lowering suppression pool level.

6:10 Licensee makes second 50.72 notification. This notification covered the Group I isolation and updated the 4:07 call made previously.