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December 11, 1995

U.S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Document Control Desk

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit No. 1; Docket No. 50-317; License No. DPR 53
Licensee Event Report 95-005
Manual Reactor Trip Due to Increasing SG 11 Water Level

The attached report is being sent to you as required under 10 CFR 50.73 guidelines. Should you have questions regarding this report, we will be pleased to discuss them with you.

Very truly yours,

Charles H. Cruse

CHC/CDS/bjd

Attachment

cc: D. A. Brune, Esquire
J. E. Silberg, Esquire
L. B. Marsh, NRC
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NRC FORM 366 (4-95)

U. S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Calvert Cliffs, Unit 1	05000 317	1 OF 10

TITLE (4)

Manual Reactor Trip Due to Increasing SG 11 Water Level

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER 05000
11	09	95	95	005	00	12	11	95	FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR : (Check one or more) (11)							
			20.2201(b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(viii)
POWER LEVEL (10)	100		20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(x)
			20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
			20.2203(a)(2)(ii)		20.2203(a)(4)		50.73(a)(2)(iv)		OTHER
			20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		Specify in Abstract below
		X	20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (include Area Code)
Craig D. Sly, Senior Engineer	410-260-4858

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	SJ	DCC	F120	Y					
E	ESB	PDS		N					

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X	YES (If yes, complete EXPECTED SUBMISSION DATE)	NO		02	28	95

ABSTRACT (Limit to 1400 spaces, i.e., approximately15 single-space typewritten lines) (16)

On November 9, 1995 at 1457 hours, an alarm notified Operators of a high Steam Generator (SG) 11 level (+15 inches). Operators verified that SG 11 level was increasing and attempted to place its feedwater regulating valve controller in the manual mode without success. Steam Generator 11 level increased to approximately +35 inches and the reactor was manually tripped.

The cause was a failure of digital feedwater control module FIC-1111. Its output signal was found to be responding with a slowly increasing signal trend causing the feedwater regulating valve to SG 11 to slowly open.

The controller was sent to the vendor for troubleshooting and a root cause analysis. Additional corrective actions are underway to address the other causal factors and lessons learned from this event.

I. DESCRIPTION OF THE EVENT

On November 9, 1995 at 1457 hours, a computer alarm in the Calvert Cliffs Control Room alerted operators to a high SG 11 level (+15 inches). By 1500, operators had verified via other indications that SG 11 level was indeed increasing and implemented Abnormal Operating Procedure, AOP-3G, "Feed Malfunctions." Since the SG 11 Feedwater Control System did not appear to be properly controlling feedwater flow, operators repeatedly attempted to place its feedwater regulating valve (FRV) controller (FIC-1111) in the manual mode. The controller did not respond. At 1501, SG 11 level had increased to approximately +35 inches and the reactor was manually tripped due to the uncontrolled increase in SG 11 water level.

After the manual reactor trip, operators initiated Emergency Operating Procedure EOP-0, "Immediate Post Trip Actions." Steam Generator Feed Pump 11 (SGFP) tripped on high discharge pressure at 1501:44. SGFP 12 was noted as not delivering flow due to its low speed. In accordance with EOP-0, operators manually tripped SGFP 12 and initiated the electric driven auxiliary feedwater (AFW) pump (AFW 13) at 1505.

The normal trip recovery was complicated by a failure of the second stage moisture separator reheater (MSR) source valves (1-MS-4025-MOV and 1-MS-4026-MOV) to close after the reactor tripped as designed. The open MSR source valves acted to increase the rate of SG steaming and caused SG pressures and Reactor Coolant System (RCS) temperature to decrease at higher than desired rates.

At 1507, AFW flow was throttled to control decreasing RCS temperature. The RCS cold leg temperature (Tc) was approaching 525 degrees Fahrenheit due to the open MSR source valves. At 1510, SG pressures had fallen to the EOP-0 action limit of less than 800 psia. In accordance with EOP-0, Operators manually closed the main steam isolation valves (MSIVs), and took manual control of the atmospheric dump valves (ADVs) to control RCS temperature. Tc reached a minimum of 524 degrees Fahrenheit.

During the plant stabilization that followed, operators had trouble maintaining a positive SG 11 level trend because ADV 11 was relieving steam at a faster rate than ADV 12. Operators made some minor adjustments to AFW flow rate in an attempt to restore a positive level trend to SG 11. However, their primary concern at this point in the event was to restore and maintain RCS Tc to greater than 525 degrees Fahrenheit. They were careful not to feed too much cold

AFW water into SG 11 and cool down the RCS. By 1513, Tc had recovered to greater than 525 degrees Fahrenheit.

Operators continued to adjust AFW flow to the SGs and dump steam through the ADVs to control RCS heat removal. The difference in ADV 11 and 12 steaming rates resulted in SG 11 level falling while SG 12 level recovered. Throughout this period, Operators were focused on maintaining RCS Tc above 525 degrees Fahrenheit. At 1527, an Auxiliary Feedwater Actuation System (AFAS) signal was generated due to low SG 11 level (below -170 inches) starting the steam-driven AFW pumps and restoring an increasing level trend in SG 11. Thereafter, the plant recovery proceeded normally, and at about 1700, operators exited EOP-1.

II. CAUSE OF EVENT

The post trip investigation team identified the following problems and issues related to this event.

A. FIC-1111 FAILURE

Initial investigation into the cause of the feedwater flow problem found that the Feedwater Control Module FIC-1111, a digital controller, had an, "Error 4, RAM Bad," message on its local digital display. The FIC-1111 controller is a Fischer Porter (FP) 2000 series digital controller. The controller was quarantined to avoid a potential loss of data pending further investigation. Post trip troubleshooting and analysis found that the output signal from FIC-1111 was linear with a slowly increasing signal trend. This resulted in the FRV to SG 11 slowly opening, leading to the increasing water level. Electrical and Controls personnel attempted to insert commands to clear the error message without destroying any evidence, but the controller did not respond. The controller was downpowered and repowered and the error message cleared. The controller then appeared to be functioning properly, its program was downloaded, checked, and found to be satisfactory.

The digital and power supply inputs into the controller were verified as operating satisfactorily. It was also verified that no work was in progress in the vicinity of the FRV or the controller prior to the controller failure.

A letter from the vendor indicated that the Error 4 "RAM Bad" error code is a rare occurrence. This error code is the result of a continuously running random access memory (ram) diagnostic. This diagnostic reads each memory cell then loads a reverse pattern (reverses 1's and 0's). It then reads the cell again to determine if the reverse pattern exists. If it does, then it reloads the pattern and goes on to the next cell. If it does not find the expected pattern, the Error 4 message is displayed and the controller shuts down, or "locks up" at a constant output. The vendor indicated that after such an error message the controller should be removed from service and tests run at a repair facility to determine the cause. Freezing at a flat, steady-state output signal (fail as-is) was the expected failure mode by the vendor and BGE.

Review of the INPO Network, the NPRDS database, and Fossil Industry databases found six examples of FP 2000 series controller failures. The most recent failure occurred on November 17, 1995, and resulted in the FRVs at St. Lucie freezing in a constant position causing the operators to manually trip the plant. The cause of this failure is unconfirmed. The other five failures all involved interruptions in the controllers' power supply, followed by a failure of the controller to reboot. There were no reports of controller failures involving an increasing output signal.

The failed controller FIC-1111 was sent offsite to Fischer Porter for a complete failure analysis at their facilities. This failure analysis is being monitored and controlled by Calvert Cliffs personnel.

B. SGFP 11 AND 12 TRIPPED

Directly after the plant trip, operators and the system engineer responsible for the main feedwater system arrived at the FRVs to monitor their performance. They observed that both FRV bypass valves were open to the proper post trip intermediate position. The system engineer was also able to observe SGFP 11 trip, and SGFP 12 runback and then trip. Review of plant computer data indicated that SGFP 11 tripped on a high discharge pressure, and SGFP 12 was manually tripped from the control room.

The cause of the SGFP high discharge pressures was that the FRVs closed, as designed, and the SGFP mini-flow (recirculation) valves did not open fast enough after the reactor trip. The proportional controller feedback loop response time of both SGFP mini-flow valves had been changed in June of 1995 to increase their response time. This was done to alleviate previously experienced problems with feedwater system startup control.

The probable cause of the SG 12 runback was that its Lovejoy controller detected a short transient discharge pressure spike that was long enough in duration to actuate the pressure transmitter that sends a trip signal to the Lovejoy, but not long enough in duration to lift the trip solenoid valve. The Lovejoy response to this would be to assume a failure of the pump's hydraulic system to respond to a valid trip signal, and then begin closing the SGFP 12 governor. Indeed, the pump speed was observed to have ramped down to between 1000 and 2000 RPM immediately after the trip. At that time, SGFP 12 was manually tripped from the Control Room in accordance with established plant procedures.

C. THE MOISTURE SEPARATOR SOURCE VALVES

The failure of the MSR source valves to close after the trip, as designed, complicated the plant post trip shutdown. Normally, after a reactor trip from power levels of greater than 63 percent, the steam dump and turbine bypass valves fully open. When T(av) falls to approximately 548 degrees Fahrenheit, the ADVs and turbine bypass valves begin to automatically modulate. The ADVs modulate to maintain RCS T(av) to between 535 and 540 degrees Fahrenheit while the turbine bypass valves modulate to maintain SG pressure to between 895 and 900 psia.

The open MSR second stage source disrupted control of SG pressure by providing an unmodulated steam discharge path from the SGs. This resulted in a high rate of removal of energy from the SGs and the RCS and ultimately led to the need for operators to close the MSIVs and take manual control of the ADVs in order to control RCS temperature.

Troubleshooting found a problem with a differential pressure switch that provides the closure signal to both of the MSR second stage source valves. The differential pressure switch 1-PS-4025 was found to have a leaking bellows. The leaking caused the setpoint of the pressure switch to effectively change. The leaking also resulted in the formation of deposits inside the pressure switch causing some binding of the switch mechanical internals. The switch was replaced.

Additional investigation found that the switch had been in the plant for some time. A review of the equipment database for Units 1 and 2 found that only one other switch of the same model exists at Calvert Cliffs, 1-PS-4026. This switch was inspected and found to be in acceptable operating condition.

D. FEEDWATER BYPASS VALVE DID NOT INDICATE OPEN

Shortly after the trip, both feed regulating bypass valves (FRBVs) were visually verified by operators and the system engineer to be open locally at the valves themselves. However, control room indication did not change after the trip to show that FRBV 11 was open. The FRBVs indicate open when their indicating light changes from green (closed) to red and green (intermediate open). After the trip the FRBV 11 indication remained green.

Troubleshooting of the problem found a sticking limit switch was the cause of the problem. The limit switch was replaced and other FRBV limit switches were checked for proper operation.

E. ADVs RELIEVING AT DIFFERENT RATES

A calibration was performed on both ADV 11 and 12 I/P controllers. Atmospheric Dump Valve 11 I/P (I/P 3938) was found to be out of calibration at three percent higher than desired. This was probably the result of instrument drift since the prior refueling outage in the spring of 1994. Atmospheric Dump Valve 12 I/P controller (I/P 3939) was found to be within its calibration specifications, but 1.5% higher than desired. A check of the valve mechanical positioners found the ADV 11 positioner controlled the valve full stroke from 3-15 psi input. The ADV 12 positioner controlled the valve full stroke from 4-16 psi input. Both valves I/P controllers receive the same controller input. The net result of the difference in I/P setpoints and valve mechanical positioner alignments was that ADV 11 went to a higher position and relieved steam at a faster rate than ADV 12 with the same input signal. This problem caused operators to control feed to SGs 11 and 12 at different rates.

Both ADV control circuits were realigned and stroked to ensure they both lifted to the same position.

IV. SAFETY IMPLICATIONS

A. SAFETY CONSEQUENCES

This event did not result in a significant challenge to plant safety. The event that initiated the reactor trip was a SG 11 overfeed due to the FIC-1111 failure. The resulting increasing SG 11 level was conservatively mitigated by plant operators who manually tripped the reactor at a SG 11 level of +35 inches. Had the operators not manually tripped the reactor, an automatic reactor trip would have occurred at SG 11 level of +50 inches. The plant is designed to trip and safely recover from a high level in either or both SGs without any adverse effects on the plant.

B. POTENTIAL SAFETY CONSEQUENCES

There were several complicating factors surrounding this trip. Specifically;

1. The MSR second stage source valves failed to close after the trip as designed, increasing the rate of SG steaming, and causing SG pressures and RCS temperature to decrease. Ultimately, this problem required operators to close the MSIVs and use the ADVs to control RCS temperature. The MSIVs were closed with SG pressures at about 800 psia. The manual closure of the MSIVs was a conservative action that minimized the cooldown of the RCS. If the operators had not manually closed the MSIVs, a steam generator isolation signal would have automatically closed them at 685 psia steam pressure and restored RCS temperatures.

   Decreasing RCS temperature after a reactor trip is a potential concern due to the positive reactivity from moderator and fuel temperature feedbacks. The positive reactivity addition will erode the negative reactivity added by insertion of the control element assemblies. The Updated Final Safety Analysis Report safety analysis for a main steam line break inside and outside of the containment analyze such event scenarios. The outside containment MSLB event analysis bounds this particular event and concludes that the negative reactivity added by the control element assemblies will be sufficient to maintain the reactor subcritical.

2. Both SGFPs tripped (one automatically, one manually), requiring the manual initiation of the electric-driven AFW train. This resulted in AFW becoming the source of feed to the SGs. The manual initiation of AFW was a conservative action that minimized the potential for a low SG level during the trip recovery. Automatic actuation of the AFW System occurs when either SG reaches a level of -170 inches.

3. ADVs 11 and 12 relieved steam at different rates resulting in SG levels decreasing at different rates. This problem had no effect on the ability of AFW pumps to deliver feedwater to the SGs, the ability of operators to manually control the feed rate to each SG, or the ability of AFAS to actuate and make up SG levels when one SG reached a level of -170 inches.

The plant condition that resulted from this event is bounded by the Updated Final Safety Analysis Report Safety analysis concerning Main Steam Line Break (MSLB). The MSLB analysis assumes a variety of break sizes and locations that bound this event and concludes that the reactor will remain subcritical. Based on the discussion above, this event did not result in a significant threat to the health and safety of the public or on-site personnel.

C. GENERIC IMPLICATIONS

The generic implications of the FIC-1111 failure is not yet known and depends on the results of the root cause analysis. The results of the FIC-111 root cause analysis and investigation team findings will be detailed in a Supplement to this LER. The expected submission date is February 28, 1996.

V. CORRECTIVE ACTIONS AND RECOMMENDATIONS

A. CONCERNING FIC-1111

1. The controller was sent off-site to Fischer Porter for troubleshooting and a root cause analysis. We are overseeing the process to ensure the root cause analysis is done correctly.

2. A failure modes and effects analysis for the newly experienced FIC-1111 (ramping up) controller failure mode

is being conducted and will be extended to include any replacement controllers.

3. We are evaluating potential modifications that will add redundancy or a hard manual override to the important digital controllers in the plant. We are also considering the use of an alarm that will warn operators of a controller failure.

B. TRIPPING OF SGFPs

We will evaluate the response time of the SGFP mini-flow valve proportional controller and recommend the best response configuration that will support all phases of plant operations including startup, full power and shutdown control.

C. MSR SECOND STAGE SOURCE VALVES

We will evaluate the actual history of the pressure switch (1-PS-4025) that failed and develop recommendations concerning establishment of a replacement frequency for this type of switch in the preventative maintenance program.

D. FEEDWATER BYPASS VALVE INDICATION

We will evaluate the need for more frequent Preventative Maintenance on the limit switches associated with the FRV and FRBV indication.

E. ADV STEAM DISCHARGE AT DIFFERENT RATES

We will determine if the as found condition of the ADVs was appropriate or the result of abnormal drift and/or controller misalignment and make recommendations that will minimize the potential for future ADV misalignments.

IV. ADDITIONAL INFORMATION

A. There have been no previous similar reactor trips involving a failure of the digital feedwater controllers at Calvert Cliffs.

B. Identification of components and systems described in this report.

Component or System	IEEE 803 EIIS Funct	IEEE 805 System ID
Atmospheric Dump Valve	RV	JI
Feedwater Regulating Valve	FCV	SJ
Feedwater Bypass Valve	FCV	SJ
Pressure Switch	63	SB
Feedwater Regulating Valve Controller	FCO	SJ
Moisture Separator Reheater Source Valves	ISV	SB
Steam Generator Feed Pump	P	SJ
Auxiliary Feedwater Pump	P	BA
Digital Feedwater Controller	DCC	SJ