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Docket No. 50-321

HL-5895

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Edwin I. Hatch Nuclear Plant - Unit 1
Licensee Event Report
Reduction in Reactor Feedwater Flow Results in
Automatic Reactor Shutdown on Low Water Level

Ladies and Gentlemen:

In accordance with the requirements of 10 CFR 50.73(a)(2)(iv) and (v), Southern Nuclear Operating Company is submitting the enclosed Licensee Event Report (LER) concerning a reduction in reactor feedwater flow which resulted in an automatic reactor shutdown on low water level.

Respectfully submitted,

Lewis Sumner

H. L. Sumner, Jr.

OCV/eb

Enclosure: LER 50-321-00-002

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IE22

NRC FORM 366 (06-1998) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 06/30/2001
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)	Estimated burden per response to comply with this mandatory information collection request: 50 hrs. Reported lessons learned are incorporated into the licensing process and fed back to industry. Forward comments regarding burden estimate to the Information and Records Management Branch (T-6 F33), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503. If a document used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

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TITLE (4)
Reduction in Reactor Feedwater Flow Results in Automatic Reactor Shutdown on Low 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(S)
									Plant Hatch Unit 2	05000366
01	26	2000	2000	002	00	02	25	2000		05000

OPERATING MODE (9)	1
POWER LEVEL (10)	100

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)(vii)
	20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(ix)
	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)	X	50.73(a)(2)(iv)		OTHER
	20.2203(a)(2)(iii)		50.36(c)(1)	X	50.73(a)(2)(v)		Specify in Abstract below or in NRC Form 366A
	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)
Steven B. Tipps, Nuclear Safety and Compliance Manager, Hatch	(912) 367-7851

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX
B	SJ	HS	G080	Yes						

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

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-space typewritten lines) (16)

On 01/26/2000 at 0653 EST, Unit 1 was in the Run mode at a power level of 2763 CMWT (100% of rated thermal power) when the reactor shut down automatically, and the Group 2 Primary Containment Isolation Valves (PCIVs) closed on low water level. Water level decreased when feedwater flow was reduced following the unexpected closure of an inlet valve to a feedwater heater. Following shutdown, water level continued to decrease due to a void collapse from the rapid reduction in power, resulting in closure of the Group 5 PCIVs and automatic initiation of the Reactor Core Isolation Cooling (RCIC) and High Pressure Coolant Injection (HPCI) systems. The secondary containment dampers automatically isolated, and all trains of the Unit 1 and Unit 2 Standby Gas Treatment systems automatically started on low water level. Water level reached a minimum of 54 in. below instrument zero. The Reactor Feedwater Pumps, and the RCIC, HPCI, and Control Rod Drive systems restored level to > 40 in. above instrument zero within 40 sec of the shutdown. Pressure decreased from its normal value of 1030 psig to a minimum of 746 psig approximately 2 min following shutdown. At that time, the main steam line isolation valves (MSIVs) were closed because water level was approaching the main steam line nozzles. MSIV closure caused pressure to increase to a maximum of 1085 psig approximately 17 min following shutdown. Pressure was reduced and controlled using manual and automatic safety/relief valve actuation. The feedwater heater inlet valve closed upon receipt of an apparent spurious signal from its control switch. The inlet valve closure was most likely the result of a slight jarring of either the control switch or its panel. Switches of this type have been known to actuate with very little movement of the control mechanism. The delay of the HPCI system to trip automatically at its high level setpoint resulted in water level reaching the main steam line nozzles. Testing of the level transmitters, trip units, relays, and logic system revealed no reason for the delay in tripping. Corrective actions include replacing control switches, reviewing the type and frequency of logic system testing, and additional operator training.

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor
Energy Industry Identification System codes appear in the text as (EIIS Code XX).

DESCRIPTION OF EVENT

On 01/26/2000 at 0652 EST, Unit 1 was in the Run mode at a power level of 2763 CMWT (100% of rated thermal power) when reactor pressure vessel (RPV) water level began decreasing as the result of a substantial reduction in the reactor feedwater flow rate following an unexpected closure of the inlet valve to high-pressure feedwater heater 1N21-B006B (EIIS Code SN). When water level decreased to the low level alarm setpoint of 32 in. above instrument zero (190.44 in. above the top of the active fuel), the low water level annunciator alarmed in the main control room. Licensed Operations personnel took manual control of the Reactor Feedwater Pumps (RFPs, EIIS Code SJ) and increased the pumps' output in an attempt to restore water level to its normal value of approximately 37 in. above instrument zero. However, RPV water level continued to decrease, and at 0653 EST, the reactor shut down automatically on low RPV water level. The outboard Group 2 Primary Containment Isolation Valves (PCIVs, EIIS Code JM) received a closure signal, with the inboard Group 2 PCIVs receiving a signal 8 sec later. All Group 2 valves closed as expected.

Following the automatic reactor shutdown, RPV water level continued to decrease due to a void collapse from the rapid reduction in power, resulting in closure of the Group 5 PCIVs and automatic initiation of the Reactor Core Isolation Cooling (RCIC, EIIS Code BN) and the High Pressure Coolant Injection (HPCI, EIIS Code BJ) systems at 35 in. below instrument zero. The secondary containment automatically isolated, and all four trains of the Unit 1 and Unit 2 Standby Gas Treatment (EIIS Code BH) systems (SGTS) automatically started. Water level reached a minimum of approximately 54 in. below instrument zero (104.44 in. above the top of the active fuel) before the RFPs, and the RCIC, HPCI, and Control Rod Drive (CRD, EIIS Code AA) systems restored level. RPV water level increased to > 40 in. above instrument zero within 40 sec of the automatic shutdown.

At approximately 0654 EDT, the RFPs and the RCIC system tripped on high RPV water level per design. However, the HPCI system failed to trip on high RPV water level as required. With RPV water level at approximately 50 in. above instrument zero and < 20 sec before the trip of the RFPs and the RCIC system, personnel took manual control of the HPCI system, reducing turbine speed until the injection flow rate was zero. Ten seconds later, with RPV water level at approximately 46 in. above instrument zero, the HPCI controller was returned to automatic. Since the HPCI initiation signal was still present, turbine speed increased until the injection flow rate reached its nominal setpoint value of 4250 gal/min. RPV water level reached 51.5 in. above instrument zero 8 sec after injection flow was restored; however, the HPCI system failed to automatically trip at that setpoint. Therefore, HPCI continued to inject water into the RPV, increasing level to a maximum indicated value of 110.8 in. above instrument zero. At 0655 EST, approximately 1 min after RPV water level had reached its nominal high-level trip setpoint of 51.5 in. above instrument zero and with indicated water level at 110.6 in. above instrument zero, the HPCI system tripped automatically. With RPV water level at this height, continued CRD injection and expansion of the cold water, resulting from core decay heat, caused substantial quantities of RPV water to enter the main steam lines (MSLs).

Injection of cold water by the RCIC and HPCI systems caused RPV pressure to decrease steadily from its normal value of 1030 psig at the time of the automatic reactor shutdown to a minimum of 746 psig approximately 2 min following shutdown. Operations personnel closed the main steam isolation valves (MSIVs, EIIS Code SB), as required by procedure, because RPV water level was near the height of the MSL nozzles. MSIV closure and the heating of cold water resulted in a slow increase in RPV pressure to a maximum of 1085 psig approximately 17 min following shutdown. MSIV closure also resulted in inadvertently filling the portion of the MSLs from the vessel nozzles to the closed inboard MSIVs as water continued to enter the lines.

With RPV pressure at approximately 960 psig, licensed Operations personnel attempted to manually open 1 of the 11 SRVs (SRVs, EIIS Code SB), as required by plant procedure. The opening of one SRV normally results in illumination of: 1) the red "open" light and an RPV pressure decrease, and 2) an amber light, which indicates flow past two tailpipe pressure switches (EIIS Code JE) on the SRV discharge line. These pressure switches initiate at 85 psig. However, on the first seven SRVs the operator opened, the tailpipe pressure switches did not actuate as expected. It was subsequently determined that tailpipe pressure switches generally do not actuate if the associated SRV is passing subcooled water, not steam. The MSLs contained sufficient subcooled water such that the SRVs were actually passing water when first opened. Therefore, the tailpipe pressure switches did not actuate. Although all seven SRVs actually opened upon demand, as proven by their tailpipe temperature traces, the failure of the pressure switches to actuate gave the appearance that none of the SRVs had opened. Because an "open" indication was not received and no apparent decrease in RPV pressure was observed, the operator continued to open the SRVs until a tailpipe pressure switch indicated that a valve had opened. This indication was received when the eighth SRV, 1B21-F013B, was opened.

The pressure switches for SRV 1B21-F013B actuated upon initial valve opening. Apparently, the control switch for SRV 1B21-F013A was inadvertently left open during the earlier attempt to open an SRV, thereby allowing the water in the "A" MSL (upon which SRVs 1B21-F013A and 1B21-F013B are located) to drain before the operator attempted to open valve 1B21-F013B. When opened, valve 1B21-F013B passed either steam or a steam/water mixture of sufficient energy to actuate the tailpipe pressure switches for valve 1B21-F013B. This in turn actuated the Division I low-low set (LLS) logic subsystem as designed. LLS SRVs 1B21-F013H and 1B21-F013G opened automatically as expected and as confirmed on SRV tailpipe temperature traces. Division II of the LLS logic subsystem did not actuate, because it did not receive a tailpipe pressure switch actuation signal concurrent with a high RPV pressure signal. Because RPV pressure was very near the nominal high RPV pressure trip setpoint of 1080 psig, the pressure sensors that provide a signal to the Division II logic did not sense a high-pressure condition and thus, did not generate a Division II logic actuation signal.

The tailpipe pressure switches for SRVs 1B21-F013H and 1B21-F013G did not sense adequate pressure to actuate when the Division I LLS logic subsystem automatically opened these valves. Since no apparent indication that these two valves were open was received, the operator first used SRV 1B21-F013B, and then SRV 1B21-F013A after it indicated "open," to manually reduce RPV pressure. Within approximately 5 min, RPV pressure was reduced from 1085 psig when Division I LLS logic actuated and SRVs 1B21-F013G and 1B21-F013H opened to 819 psig when the operator manually closed the last open safety/relief valve. Operations personnel subsequently used a combination of manual and automatic operation of the SRVs and the HPCI system in the pressure control mode to maintain RPV pressure below 920 psig.

CAUSE OF EVENT

RPV water level decreased to the automatic reactor shutdown setpoint following a substantial reduction in RPV feedwater flow that occurred when high-pressure feedwater heater inlet valve 1N21-F005B (EIIS Code SJ) closed unexpectedly, isolating one of the two feedwater inlet lines. The inlet valve to the high-pressure feedwater heater closed when it apparently received a "close" signal from its control switch. A conclusive determination of the cause of the switch closure was not made. The switch action seems to have been spurious and may have been the result of inadvertent or slight jarring or vibration of either the switch or the panel in which the switch is located.

It should be noted that switches of the type used to position the inlet valve have been known to actuate with very little movement of the control mechanism and as a result, were the subject of General Electric (GE) Service Information Letter (SIL) 217, issued 2/28/77. The site response to SIL 217, completed 11/5/81, stated that the SIL's recommendation to replace the overly sensitive switches with newer switches would be implemented, as necessary, since Unit 1 and Unit 2 had been in service approximately 6 and 2 years, respectively, with no apparent problems.

In addition, the same type of switch failed in a similar manner on Unit 1 on 10/5/1996, causing a partial loss of feedwater heating and necessitating an approximate 20% decrease in reactor power. The event was determined to require a cause determination and therefore, was entered into the Plant Hatch corrective action program as described in plant procedure 10AC-MGR-004-0S, "Condition Reporting System." The response to this event resulted in the replacement of several switches located on the same panel as the failed switch. However, the corrective actions did not extend to switches on other panels or on the other unit. At the time, this appeared reasonable based upon the lack of previous similar events (1 failure in 15 years of operation) since the SIL was issued.

RPV water level reached the height of the MSL nozzles, because the HPCI system failed to trip automatically at its high RPV water level setpoint. Operations personnel briefly took manual control of the HPCI system and reduced its injection flow rate to zero. Based on the subsequent response of the system, the controller was restored to automatic control and operators did not note that the system had not tripped automatically at the appropriate setpoint. Therefore, the HPCI system was not manually tripped. Consequently, water entered the MSLs, adversely affecting the indication of some SRV tailpipe pressure switches. However, SRV operation in the manual and LLS logic modes was not adversely affected.

Testing of the water level transmitters, trip units, relays, and logic system revealed no reason for the initial delay of the HPCI system to trip at its nominal high RPV water level trip setpoint of 51.5 in. above instrument zero. The HPCI system automatically tripped three times following the automatic reactor shutdown. The first trip occurred with water level at 110.6 in. above instrument zero; however, the second and third trips apparently occurred at the nominal trip setpoint. The automatic trips exercised the logic components, including trip units, relay coils, relay contacts, and the turbine trip solenoid valve. After the initial failure to trip, the subsequent trips effectively prevented the examination of the logic system components in their as-found condition. Since the initial problems cleared and the logic system no longer was in its as-found condition, extensive checks of the various components in the high RPV water level trip logic system did not identify the cause of the initial trip delay.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This report is required by 10 CFR 50.73 (a)(2)(iv) because of the unplanned actuation of Engineered Safety Feature (ESF) systems. Two ESF systems; i.e., the Reactor Protection System (RPS, EIIS Code JC) and the Group 2 Primary Containment Isolation System (PCIS), actuated on low RPV water level. Following the automatic reactor shutdown, water level decreased due to a void collapse, resulting in the receipt of an automatic Group 5 PCIS isolation signal on low RPV water level, which caused automatic initiation of the RCIC and HPCI systems. The secondary containment automatically isolated, and all four trains of the Unit 1 and Unit 2 SGTSs automatically started on low RPV water level.

This report is also required by 10 CFR 50.73 (a)(2)(v), because the HPCI system, a single-train safety system, was rendered inoperable when the system failed to trip automatically on high RPV water level.

Low RPV water level indicates the capability to cool the fuel may be threatened. Should water level decrease too far, fuel damage can result. Therefore, an automatic reactor shutdown is initiated to substantially reduce the heat generated in the fuel by fission. The automatic reactor shutdown reduces the amount of energy required to be absorbed and, along with the actions of the emergency core cooling systems (ECCSs), ensures the fuel peak-cladding temperature remains below the limits of 10 CFR 50.46.

The HPCI system is a high-pressure ECCS designed to operate in conjunction with the RPS and is provided to ensure the reactor is adequately cooled to limit fuel-cladding temperature in the event of a small break in the nuclear system and a loss of coolant that does not result in rapid RPV depressurization. The HPCI system permits the plant to be shut down, while maintaining sufficient RPV water inventory until the vessel is depressurized. The HPCI system continues to operate until RPV pressure is below the pressure at which other ECCSs can maintain cooling.

High RPV water level indicates there is sufficient cooling water inventory in the RPV to protect the fuel. Therefore, a high RPV water level signal is used to trip the HPCI system turbine to prevent water overflow into the MSLs. However, the high RPV water level trip function is not assumed in any accident or transient analysis.

To provide timely protection against the onset and consequences of accidents involving the gross release of radioactive material from the fuel and nuclear system process barriers, the PCIS initiates automatic isolation of lines that penetrate the primary containment whenever monitored variables exceed operational limits. A low RPV water level can indicate that either coolant is being lost through a breach in the nuclear system process barrier or the normal supply of reactor feedwater has been lost and the core is in danger of becoming overheated. Low RPV water level initiates closure of various PCIVs to isolate a line breach, conserve reactor coolant, and prevent the escape of radioactive material from the primary containment.

The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code requires that self-actuated SRVs protect the RPV from overpressurization during upset conditions. The 11 SRVs located on the MSLs between the RPV and the first isolation valve within the drywell are designed to prevent peak pressure in the nuclear system from exceeding Code limits for the reactor coolant pressure boundary.

The SRVs actuate in either of two modes: the safety mode or the relief mode. 1) In the safety mode, the spring-loaded pilot valve opens when steam pressure at the valve inlet overcomes the spring force holding the valve closed. Opening the pilot valve allows a pressure differential to develop across the main valve piston and open the main valve. Each SRV discharges steam through a discharge line to a point below the minimum water level in the suppression pool. 2) In the relief mode, an open signal is sent to a solenoid-operated valve associated with each SRV, causing the valve to remove the spring force holding the respective pilot valve closed. The main valve opens regardless of steam pressure at the pilot valve inlet, allowing RPV pressures determined by the desired relief mode to open the SRV.

There are three relief modes in which the SRVs can actuate, two of which are the LLS logic mode and the Automatic Depressurization System (ADS) mode. 1) Four of the 11 SRVs can operate in the LLS logic mode. The LLS logic causes the LLS valves to open at a lower pressure than their safety mode pressure setpoints and stay open longer so that the reopening of all SRVs is prevented on subsequent actuations. Limiting the time before an SRV subsequent actuation allows the water leg in the SRV discharge line piping to reach its normal level, thereby minimizing the loading on the SRV discharge line piping, pipe supports and torus. 2) The remaining 7 SRVs can operate in the ADS mode, which is designed to depressurize the reactor coolant system during a small-break loss-of-coolant accident if the HPCI system fails or is unable to maintain the required RPV water level. ADS operation reduces RPV pressure to within the operating pressure range of the low-pressure ECCSs so they can provide coolant inventory makeup. 3) The third relief mode, an electrical actuation logic mode, augments the safety mode. Designated RPV pressure sensors transmit signals to trip units that, should pressure reach their designated setpoints, send an open signal to the solenoid-operated valve associated with each of the 11 SRVs. The SRVs then open, relieving excessive RPV pressure just as they do in the safety mode. The trip units reset, closing the SRVs at a pressure below the safety mode closing pressure. The electrical actuation logic is non-safety related. Because RPV pressure did not reach the trip unit actuation setpoints, this logic was not challenged during the event.

In this event, the reactor shut down automatically, and Group 2 PCIVs closed on low RPV water level, which resulted from a decrease in feedwater flow rate caused by unexpected isolation of one of the two RPV feedwater lines. As water level continued to decrease due to a void collapse from the rapid decrease in reactor power, Group 5 PCIVs closed; the HPCI and RCIC systems initiated; the secondary containment isolated; and the SGTS trains started at their respective setpoints.

Following recovery of the RPV water level, the HPCI system failed to trip at its high RPV water level setpoint, allowing RPV water level to increase to the height of the MSL nozzles. In response to the high RPV water level, operations personnel closed the MSIVs as required by plant procedure. With the RPV isolated and RPV pressure increasing, operations personnel attempted to reduce and control pressure by opening an SRV. However, the operator received no indication (illumination of amber light from the tailpipe pressure switch and reduction in reactor pressure) an SRV had opened and, therefore, continued to open the SRVs until the expected indication was received when the eighth SRV opened.

Based upon an extensive review of computer and recorder data, Event Review Team personnel concluded the SRVs had opened upon receipt of either an automatic or a manual demand. Further review determined the tailpipe pressure switches that provide indirect indication the SRVs are open generally will not actuate if the associated SRV is passing subcooled water, not steam. Lower enthalpy mediums, such as subcooled water, undergo less expansion in the tailpipe, resulting in smaller propagating pressures. Therefore, when the SRV opens, the tailpipe pressure is significantly lower with water than with steam.

With sufficient quantities of water in the MSLs, water initially passed through the SRVs when they were first opened. Therefore, tailpipe pressure was not sufficient to actuate the pressure switches, and RPV pressure apparently did not decrease, leaving the operator with no front-panel indication the valves had opened when the control switches were placed in the open position.

When an SRV is operated with water in its steam line, a delay of several seconds is possible before the SRV main disk opens. Nonetheless, the SRVs satisfactorily provided overpressure protection during this event even with a delay in valve operation. The ability of the SRVs to operate with significant quantities of water in the MSLs was demonstrated by a series of water discharge tests as documented in GE topical report NEDE-24988-P, "Analysis of Generic BWR Safety Relief Valve Operability Test Results," issued in October 1981. This report was generated to support alternate shutdown cooling operation, a mode in which the vessel is flooded with the MSIVs closed, allowing RPV water to flow through the SRVs to the suppression pool. The documented results from multiple tests of SRVs operating in a subcooled water environment demonstrated that SRVs, upon demand, will consistently open and close in a subcooled water environment, as Plant Hatch computer and recorder data indicated during this event.

The automatic vessel overpressure protection function (the safety mode) of the SRVs was preserved for this event. GE evaluated the RPV response using the SAFER thermal-hydraulic computer code and assuming the HPCI system continues to operate above the high-level trip as occurred in this event. Other plant conditions were simulated as closely as possible. The analysis concluded that the few seconds delay in SRV opening due to water in the MSLs was insignificant, because the RPV pressurization rate in a shutdown condition is very low, as demonstrated by the actual plant response in this event. Assuming that personnel took no action and RPV pressure reached the nominal SRV mechanical relief setpoint of 1150 psig, the SAFER code predicted a pressurization rate of < 1 psi/sec for this event. The Code also predicted it would take 8 min for pressure to reach the Code-maximum steam dome pressure of 1325 psig. The Architect/Engineer calculated that water collected in the MSLs between the RPV and the SRVs would be cleared through the nearly 5-in.-diameter throat of the SRVs in < 75 sec. Therefore, adequate time is provided to open the SRVs, drain whatever water is in the MSLs, and relieve steam to the suppression pool before RPV pressure increases significantly, thus ensuring adequate margin to Code limits.

The LLS logic system can be actuated only upon the actuation of the pressure switches in the tailpipe of at least one SRV. Subcooled water passing through the SRV delays actuation of the pressure switch, resulting in a corresponding delay of the LLS logic system actuation. However, this delay has no adverse effect upon the function of LLS, which is designed to prevent excessive, short-duration relief valve cycles that will otherwise occur with SRV actuation only at the relief setpoint by causing some SRVs to stay open longer. This prevents RPV pressure from remaining near the SRV mechanical relief setpoint, causing the valves to open repeatedly as pressure marginally exceeds the relief setpoint and close as pressure drops marginally below the setpoint.

Assuming no action is taken or occurs to open the SRVs sooner, they will open when RPV pressure reaches the mechanical relief setpoint of 1150 psig. The valves will clear the MSLs of water and lower RPV pressure. The minimum required number of pressure switches will likely actuate during this time, thereby actuating the LLS logic system and causing the LLS SRVs to remain open, as designed, even when pressure drops below the mechanical relief setpoint.

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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

The possibility exists that no pressure switches will actuate upon initial lift of the valves. During this event, the pressure switches in one SRV tailpipe actuated 3 min and 23 sec after the valve opened. In another case, tailpipe pressure switches did not actuate even though the SRV was open for almost 4 min. Therefore, it appears that sufficient pressure does not always develop in the tailpipe once the water column is ejected from the tailpipe into the suppression pool and steady flow is established. However, sufficient pressure to actuate the pressure switches develops upon subsequent actuations when the water column is re-established following SRV closure, which occurs when pressure drops below the mechanical lift setpoint. The presence of the water column and the passing of high-enthalpy steam results in the forces necessary to increase pressure in the tailpipe to the pressure switch actuation setpoint. Therefore, one subsequent operation of the SRVs at their mechanical relief setpoints actuates the necessary tailpipe pressure switches to actuate the LLS logic system. The LLS logic system will prevent future short-duration cycles of SRV operation, as expected. The one additional short-duration cycle needed to actuate the LLS logic system results in negligible additional SRV, tailpipe, and containment loading and, therefore, is of no safety significance.

This event did not affect the ADS mode, which is used only upon sustained and extremely low RPV water level conditions during which the RPV remains pressurized and when the HPCI system is unable to maintain RPV water level, and pressure must be reduced to allow the low-pressure ECCSs to inject coolant into the RPV. Neither of these conditions existed during this event. The HPCI system was capable of maintaining, and indeed did maintain, RPV water level well above the point at which the ADS mode was required. Finally, the SRVs that operate in the ADS mode were capable of opening upon demand and reducing RPV pressure to the point at which the low-pressure ECCSs could provide makeup water.

Water in the MSLs did not prevent the SRVs from opening upon either manual or automatic demand signals. Furthermore, water would have been cleared from the MSLs and the SRVs by the time the ADS mode would have been required, because operation of the SRVs in the safety and/or LLS logic modes would have cleared any water from the MSLs. These modes would have been activated either manually or automatically, as described previously, in response to MSIV closure on high RPV water level and the resulting RPV pressure increase. Opening the SRVs would have cleared any water that could have affected subsequent SRV operations. In the unlikely event RPV water level decreased to the point at which the ADS mode is required, water would have cleared the MSLs. Therefore, the ADS mode was capable of performing its intended safety function in the manner assumed in the accident analysis.

With the exception of the one-time delay in the trip of the HPCI system on high RPV water level, all systems functioned as expected given the water level transient. Water level was maintained well above the top of the active fuel throughout the transient. RPV pressure control via the SRVs was available throughout the event. Any effects in SRV function were minor and did not prevent the SRVs from operating in their safety, LLS logic, or ADS mode. The RPV pressure limit specified by the ASME B&PV Code was not exceeded. Therefore, it is concluded the event had no adverse impact on nuclear safety and is not considered risk significant. This analysis is applicable to all power levels.

CORRECTIVE ACTIONS

The control switch for valve 1N21-F005B was replaced. Additionally, site and corporate personnel identified possible locations of other suspect switches and developed a priority list of switches to be inspected and, if necessary, replaced with a different type of switch. Based upon these lists and the assigned priority, approximately 97 Unit 1 switches were inspected, and about 50 were replaced prior to unit startup. These actions encompassed the switches identified as high priority and a substantial number of switches identified as medium and low priorities. In some cases, switch inspection consisted of reviewing plant drawings and verifying that a switch was not the kind addressed in GE SIL 217. In all other cases, switch inspection consisted of field verification of the type of switch installed. Most switch replacements consisted of removing a switch of one type and replacing it with a switch of another type. A few switches of the correct type were replaced because of unrelated problems such as high contact resistance.

The remaining Unit 1 switches and the Unit 2 switches will be inspected and, if necessary, replaced on a schedule determined by importance to safety and plant operation, unit status necessary for inspection and replacement, and parts and manpower availability.

Site personnel performed a fault-tree analysis of the failures necessary to prevent the HPCI system from tripping automatically on high RPV water level. Possible causes including components from the water level sensors to the turbine trip solenoid valve were investigated and eliminated systematically. However, no logic or component problems were discovered.

Engineering personnel concluded that two failure modes were more likely than others: 1) dirt on relay contacts and 2) a sticking turbine trip solenoid valve. The suspect relays were removed, and visual examination and testing were performed. Although no problems were found, the relays were replaced. Resistance and voltage readings on the turbine trip solenoid valve coil were taken, and no problems were identified. To help ensure continued proper operation of the turbine trip solenoid valve, its testing frequency was increased temporarily to once per week from its normal frequency of once per quarter. The need for permanent changes to the type and frequency of testing of the turbine trip solenoid valve and trip logic components is under consideration.

Site engineering support personnel, at the direction of corporate design personnel, visually inspected portions of the MSLs, the HPCI and RCIC system steam supply lines, and the SRV discharge lines. No problems that affected operability were found with any piping or piping supports.

Licensed operators on shift were given special event training prior to the subsequent reactor startup. The training emphasized 1) the operation of SRVs and their tailpipe pressure switches with a water/steam mixture, and 2) the importance of verifying automatic actions and manually performing these actions if any automatic actions fail. Additionally, this event and lessons learned will be covered for <u>all</u> licensed personnel in the next training segment.

Two RCIC system steam supply line pressure transmitters were found damaged, explaining the failure of steam supply line isolation valve 1E51-F008 (EIIS Code JM) to close on low steam supply pressure. The transmitters appear to have been damaged; that is, their bourdon tubes were partially and permanently straightened during or following the intrusion of water into the MSLs. The damage most likely resulted from excessive forces generated by water slugs or water flashing in the supply line when the RCIC system was manually started. The resulting damage caused the transmitters to sense a higher supply pressure than actual; thus, a low-pressure isolation signal to valve

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1E51-F008 was not generated. The other isolation valve did close as required, providing the required isolation of the steam supply line. Other instruments on the main steam, the HPCI, and the RCIC systems' steam supply lines were checked, and two additional transmitter problems were identified. One of the MSL high flow transmitters was found to be out of procedural tolerance and could not be adjusted to within allowable tolerances. Likewise, one of the RCIC system steam supply line high-flow transmitters was out of tolerance and could not be adjusted to meet procedure requirements. All four transmitters were replaced.

As a precautionary measure, the pilots from the 11 Unit 1 SRVs were removed and replaced prior to unit restart. The removed pilots were sent to a qualified facility for inspection, testing, and any necessary refurbishment. The SRV pilots were tested and found to perform satisfactorily. Inspections revealed no problems or unexpected wear or damage.

ADDITIONAL INFORMATION

No systems other than those already mentioned in this report were affected by this event.

This LER does not contain any permanent licensing commitments.

Failed component information:

Master Parts List No.:	1N21-F005B	EIIS System Code: SJ
Manufacturer:	General Electric	Reportable to EPIX: Yes
Model No.:	CR2940-US203A	Root Cause Code: B
Type:	Switch, Hand	EIIS Component Code: HS
Manufacturer Code:	G080	

A previous similar event occurred on 10/5/1996 when extraction steam supply isolation valve 1N22-F020A unexpectedly closed, causing a partial loss of feedwater heating. Although not reportable, the event necessitated an approximate 20% reduction in reactor thermal power. The previous event was caused by the same control switch problem that caused valve 1N21-F005B to close, resulting in the replacement of several switches located on the same panel as the failed switch. However, the corrective actions for the previous event did not extend to switches on other panels or on the other unit. At the time, this appeared reasonable based on the lack of previous events and the relatively small consequences of the switch failure.