NRC Form 366
(9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
PLANT HATCH, UNIT 2	0 5 0 0 0 3 6 6	1 OF 1 2

TITLE (4)
PROCEDURE DEFECT AND PERSONNEL ERRORS CAUSE SYSTEM INOPERABILITY AND ESF ACTUATIONS

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 NAMES	DOCKET NUMBER(S)
0 6	1 6	8 7	8 7	0 0 4	0 1	0 3	2 5	8 8		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 0 9 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
Raymond D. Baker, Nuclear Licensing Manager - Hatch	4 0 4 5 2 6 - 7 0 1 6

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

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 fifteen single-space typewritten lines) (16)

On 6/16/87 at approximately 1724 CDT, plant operations personnel performed a surveillance on the High Pressure Coolant Injection (HPCI EIIS Code BJ). The system was behaving erratically and HPCI was determined to be incapable of performing its intended safety function.

Corrective maintenance was initiated on the HPCI system and on 6/18/87, two Primary Containment Isolation System (PCIS EIIS Code JM) HPCI steam supply valve isolations occurred. These isolations were unplanned actuations of an Engineered Safety Feature (ESF).

The root causes for the events were: 1) a defective procedure, and 2) personnel errors. Specifically, a calibration procedure did not contain sufficient directions (or allow the use of reverse or direct acting governors), and on site and vendor personnel did not verify that correct parts were issued.

Corrective actions for these events included: 1) replacing equipment, 2) checking or calibrating equipment, 3) demonstrating HPCI operability, 4) issuing an As Built Notice, 5) placing spare parts on hold, 6) reviewing plant document, 7) revising or scheduling revisions to procedures, 8) initiating vendor feedback and audit reviews, 9) performing a 10 CFR Part 21 evaluation, and 10) counseling personnel.

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A. REQUIREMENT FOR REPORT

This report is required per 10 CFR 50.73 (a)(2)(iv), because unplanned actuations of an Engineered Safety Feature (ESF) occurred. This report is also required per 10 CFR 50.73 (a)(2)(v), because the High Pressure Coolant Injection (HPCI EIIS Code BJ) system was incapable of performing its intended safety function.

B. UNIT(s) STATUS AT TIME OF EVENT

This LER describes three events. The initial event describes an occurrence where an ESF was incapable of performing its intended safety function. The second and third events describe occurrences where an unplanned actuation of an ESF occurred.

On 6/16/87, Unit 2 was in the run mode at an approximate power level of 2200 MWt (approximately 90 percent of rated thermal power). This is the first event and the one where an ESF was incapable of performing its intended safety function.

On 6/18/87, Unit 2 was in the run mode at an approximate power level of 2194 MWt (approximately 90 percent of rated thermal power). This is the second event. During this event, the first ESF actuation occurred.

On 6/18/87, Unit 2 was in the run mode at an approximate power level of 2191 MWt (approximately 90 percent of rated thermal power). This is the third event. During this event, the second ESF actuation occurred.

C. DESCRIPTION OF EVENT

On 6/16/87 at approximately 1724 CDT, licensed plant personnel were in the process of performing plant procedure 34SV-E41-002-2S (High Pressure Coolant Injection). This is a HPCI pump operability surveillance procedure. During performance of the procedure, it was determined that the HPCI system could not be controlled in the automatic or manual mode with the 2E41-R612 controller.

The HPCI system was declared inoperable and a Limiting Condition for Operation (LCO) was initiated per the Unit 2 Technical Specifications section 3.5.1. Plant personnel also initiated a Maintenance Work Order (MWO) to investigate the anomalous system response.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
PLANT HATCH, UNIT 2	0 5 0 0 0 3 6 6	8 7	— 0 0 4 —	0 1	0 3 OF 1 2

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

On 6/17/87, while the HPCI system was still in the LCO, the MWO was released for work on the HPCI system. On 6/17/87, the following actions occurred:

1. Corrective maintenance was performed on the HPCI system. Maintenance personnel determined that the erratic HPCI operation was due to a faulty Electric Governor Remote servo (EGR). They disassembled the EGR to verify that none of the oil ports were blocked. It was determined that none of the ports were blocked. However, by disassembling the EGR, the environmental qualification of the part was degraded, necessitating replacing the component.
2. Maintenance personnel consulted the spare parts list from the warehouse to determine what spare parts were in current inventory that were replacements for the defective EGR. From the spare parts list, they obtained a stock number which they used to request the needed part.
3. Using the stock number from the spare parts list, a Stock Material Issue (SMI) form was generated. Warehouse personnel filled the SMI request by providing the requested part.
4. Maintenance personnel reviewed the received part number versus the SMI and verified that they had received the component requested.
5. Maintenance personnel installed the new EGR per the vendor manual.
6. Quality Control (QC) verified that the part installed was the same as that identified on the SMI.

On 6/18/87 at approximately 0515 CDT and later at 1802 CDT, licensed plant personnel were in the process of performing procedure 34SV-E41-002-2S. This procedure was being performed to verify operability of the HPCI system since corrective maintenance had been performed on it (on 6/17/87). The HPCI turbine was started and immediately tripped due to an inboard logic isolation signal generated when the inboard isolation valve (2E41-F002) closed. This valve closed on a steam line high differential pressure (high flow) signal. After the 0515 CDT event, plant personnel investigated the isolation and they performed calibrations on the isolation logic for the turbine. No problems were found. The decision was made to run the HPCI turbine and monitor the system performance both locally and in the main control room. Subsequently, the 1802 CDT event occurred. Plant operations personnel documented the anomalous system responses by initiating Deficiency Cards (DCs) for the two events.

Valve 2E41-F002, while part of the HPCI system, is also a Primary Containment Isolation System (PCIS EIIS Code JM) valve. The closure of this valve was the result of an unplanned actuation of an ESF (the PCIS). Even though the HPCI system was out of service (per the LCO), the PCIS was in service and required to be operable.

On 6/19/87, the HPCI system was still out of service in the LCO condition. On this date the following items occurred:

1. Corrective maintenance was performed on the HPCI system. Maintenance personnel determined that the cause of the isolation of the HPCI steam line was again due to a faulty EGR. They determined the EGR needed to be replaced.
2. Maintenance personnel again consulted the spare parts list from the warehouse to request the needed part (same stock number as before).
3. Using the stock number, a Stock Material Issue (SMI) form was generated and the replacement part obtained.
4. Maintenance personnel reviewed the received part number versus the SMI and again verified that they had received the requested part.
5. Maintenance personnel installed the new EGR per the vendor manual.
6. Quality Control (QC) verified that the part installed was the same as that requested in the SMI.
7. In light of the previous failures of the EGR module, a decision was made to test the EGR locally. The test was conducted by Instrument and Control (I&C) and engineering personnel and the results determined that the EGR was controlling backwards in that when the steam admission valve to the HPCI turbine should have closed, it opened and when it should have opened, it went closed.

On 6/20/87, trouble shooting for the anomalous response (EGR controlling backwards) continued. Maintenance personnel calibrated the Electric Governor Magnetic pickup (EGM) by plant procedure 57CP-CAL-068-2S (Woodward EGM EGR HPCI and RCIC Turbine Governor) and found that it calibrated properly. They concluded that the problem could be a wiring problem between the EGM and the EGR.

Site engineering, in turn, consulted with the EGR vendor. From the consultation, it was determined that the part provided by the vendor was a reverse acting EGR while the EGR that was originally in the HPCI system was a direct acting EGR. To function correctly, a direct acting EGR was required or the wiring between the EGR and the EGM needed to be rolled (switched). The direct acting and the reverse acting EGRs are identical except that two internal wires are reversed.

On 6/21/87, the system engineer provided the maintenance personnel with work instructions to roll the wires between the EGM and the EGR. Maintenance personnel performed the rolling and verified that the EGR worked properly when tested locally.

On 6/22/87, the HPCI system was tested for operability by procedure 34SV-E41-002-2S. The system passed the operability test and was declared operable. The LCO was removed and the HPCI system was returned to service.

D. CAUSE OF EVENT

In order to fully understand the event and the circumstances of the event, plant personnel investigated the spare parts replacement history of the EGRs. They determined that the original EGR was a Woodward Governor Company part number R8250-133, direct acting, clockwise actuator. This was the part type that was originally removed from the HPCI system on 6/17/87.

However, the Woodward Governor Company no longer makes part R8250-133. Instead, they now manufacture a replacement part, 9903-026. This is a direct acting clockwise actuator. They also manufacture a R9903-026 part which is a reverse acting clockwise actuator. The only difference between the 9903-026 and R9903-026 part numbers is that the wiring to the coil of the EGR has been reversed internally.

When replacement parts (for the R8250-133 EGR) were received on site, site personnel noted that a part number discrepancy existed. They requested General Electric (GE) to provide documentation that the received part was an acceptable replacement part.

GE (and subvendor Terry Turbines) furnished documentation, including a Product Quality Certificate (PQC) that indicated that the supplied parts were 9903-026, direct acting clockwise actuators. However, the parts were, in reality, R9903-026 which are reverse acting clockwise actuators. These were entered into the plant stocks. When maintenance personnel requested a replacement for the HPCI EGR on 6/17/87, one of the reverse acting EGRs was issued to them.

A reverse acting EGR could have been used in the HPCI system, if it was recognized that the EGR was a reverse acting EGR. If some of the internal wiring going to the EGR is rolled on terminals 4 and 5 at the EGM, the reverse acting EGR will function like a direct acting EGR. Maintenance personnel were not aware that they had a reverse acting EGR and therefore, did not know that the wires needed to be rolled.

As such, when the EGR was installed, plant personnel anticipated that it would close the governor valve as speed increased above the HPCI controller set point. Instead it opened the governor valve. This caused a high steam line flow condition to result and a steam line isolation occurred.

Once the above information was determined, it was possible to determine the root cause for each one of the events described in this LER.

The root cause of the 6/16/87 event is due to an error in an approved maintenance procedure. Specifically, procedures 57CP-CAL-068-1S (Woodward EGM, EGR: HPCI and RCIC Governor) [for Unit 1] and 57CP-CAL-068-2S [for Unit 2] did not contain sufficient oscillation control directions. Additionally, the procedures did not allow for a direct or reverse acting EGR replacement.

The system engineer reviewed the procedure and determined that the procedure is not clear, nor does it contain enough specific information about dynamic calibration (turbine operation) of the EGM and the EGR and their interfaces. The system engineer noted that excessive speed variation can be caused either by the EGM gain/stability potentiometers being out of adjustment or by the EGR hydraulic actuator needle valve being out of adjustment. The procedure required that the dynamic calibration be performed "as required" but should be performed every refueling outage.

Additionally, the procedure did not contain sufficient oscillation control directions. The lack of sufficient oscillation control directions resulted in the failure to properly calibrate the EGR response. This in turn, resulted in equipment instability and subsequent replacement of the EGR. The EGM was calibrated on 9/24/86, but the EGR needle valve adjustment for oscillation control was not performed (because the procedure did not require that the adjustment be performed).

The root cause of the two events that occurred on 6/18/87 is due to cognitive personnel error. The personnel error occurred on the part of the vendors (Terry Turbine and General Electric) and on the part of site personnel. The vendor personnel error occurred because the vendor supplied documentation stated that the replacement parts were in accordance with the Georgia Power Company (GPC) purchase order requirements. In fact, reverse acting rather than the specified direct acting parts were transmitted to GPC.

Both site Quality Control (QC) and materials department personnel made cognitive errors. This occurred when the site personnel failed to detect the errors that the vendors had made when the parts were received.

E. ANALYSIS OF EVENT

The HPCI system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the nuclear system where the loss of coolant does not result in a rapid depressurization of the the reactor vessel. The HPCI system operates until reactor vessel pressure is below the pressure at which the Low Pressure Coolant Injection (LPCI EIIS Code BO) operation or Core Spray (CS EIIS Code BM) system operation maintains core cooling.

With the HPCI system inoperable, core cooling is achieved via the redundant and diverse Automatic Depressurization System (ADS EIIS Code JE) operating in conjunction with the low pressure cooling systems. The Reactor Core Isolation Cooling (RCIC EIIS Code BN) system, (a system for which no credit is taken in the safety analysis), will also automatically provide makeup at reactor operating pressures upon receipt of a reactor low water level condition.

During this event, all of the required backup systems (ADS, LPCI and CS) remained operable. Additionally, the RCIC system was also operable. The operability of these systems was required and verified by compliance with the Technical Specifications, specifically section 3.5.1.

Since these events occurred at a high power level (90 percent of rated thermal power), it is not be' 'ed that the consequences of these events would be significantl ferent under other reactor power conditions. Since all of th. . quired backup systems and RCIC were capable of performing their intended safety functions, it is concluded that this event had no adverse nuclear safety impact.

F. CORRECTIVE ACTIONS

The corrective actions for this event included:

1. Replacing the original HPCI EGR actuator and checking the original EGR for blockage of oil ports. No blockage was found.

2. Checking and or calibrating plant equipment. The HPCI control loop was checked. The inboard HPCI High Steam Line delta pressure instrumentation, trip units, and time delay relay were calibrated. Plant Instrument and Control (I&C) personnel performed these activities and they found the loop and other equipment to be within calibration and functioning correctly. The HPCI EGM was calibrated per procedure 57CP-CAL-068-2 and found to be with tolerances.

3. Demonstrating HPCI operability and returning the system to service on 6/22/87. The LCO was cleared when the HPCI system was returned to service.

4. Issuing an As Built Notice (ABN). The ABN was issued against the Unit 1 and Unit 2 HPCI manuals. The ABN alerts personnel that direct acting and reverse acting EGRs can be used on the HPCI system. However, depending on the EGR type, the wiring hookup between the EGR and the EGM will be different.

5. Placing a hold on all Unit 1 and Unit 2 HPCI turbine EGRs that are in current warehouse stock. An engineering evaluation is required prior to issuance of these EGRs.

6. Reviewing plant documents. It was determined that the materials department receiving procedures adequately address part number verification. However, there was the need for desk top instructions to provide additional guidance to senior storekeepers relative to receipt processing.

   These instructions were issued on 8/24/87 and they particularly address the area of receipt discrepancy resolution (part numbers, quantities, etc.). These instructions also include foreman and supervisory involvement in the resolution of discrepancies.

   Procedural controls relative to QC parts verification were also reviewed. QC personnel concluded that the procedures are adequate, as written.

7. Revising or scheduling revisions to plant procedures. Plant procedures 57CP-CAL-068-1S (Unit 1) and 57CP-CAL-068-2S (Unit 2) were revised with an effective date of 11/11/87 and the following caution was inserted into the EGR replacement section:

   > "Caution: Depending on the EGR type, the wiring connection between the EGR and EGM will be different. New EGR's can be internally wired different which could make EGR's reverse acting or direct acting. Consult system engineer for correct type and model number."

   The procedure revisions also included the acceptance speed variation requirements (which included information related to the oscillation requirements), and the frequency of performance (every refueling outage).

   Plant procedure 55MC-MTL-001-0S (Materials Receiving) was scheduled for revision. The revision will review the procedure and, as necessary, incorporate the appropriate sections of the desk top instructions. It is anticipated that the revision process will be completed by approximately 7/1/88.

   The remaining portions of the desktop instructions, as applicable, will be incorporated into a permanent plant procedure or instruction by 7/1/88.

8. Initiating a vendor feedback form and determining if other audits of the vendor are required. The vendor feedback form was generated by the site nuclear procurement review group and sent to the corporate qualified suppliers list coordinator. This documented the method that GE handled the event. It was determined that a recent audit of the parts supplier was acceptable and additional auditing was not required.

9. Requesting a 10 CFR Part 21 evaluation of the event. The evaluation determined that the event is not reportable per the requirements of 10 CFR 21.

10. Counseling QC personnel who were involved in the event.

G. ADDITIONAL INFORMATION

1. FAILED COMPONENT(s) IDENTIFICATION

No equipment failed and contributed to this event. This conclusion is based on the root cause determination. The original EGR is believed to have been out of adjustment. If the calibration procedure had not been defective (because it did not contain sufficient oscillation control directions), it is believed the original EGR could have been adjusted and would not have been replaced.

2. PREVIOUS SIMILAR EVENTS

Previous LERs have reported events where the HPCI system was inoperable or where HPCI PCIS valves actuated. These LERs are 50-366/1986-007 (dated 2/13/86) and 50-366/1986-014 (dated 7/17/86).

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
PLANT HATCH, UNIT 2	0 5 0 0 0 3 6 6	8 7	— 0 0 4 —	0 1	1 1 OF 1 2

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

LER 50-366/1986-007 described an event where one of the HPCI PCIS valves isolated. LER 50-366/1986-014 described an event where the HPCI system was incapable of performing its intended safety function. The LER also reported an isolation of one of the HPCI PCIS valves.

The cause of the event described in LER 50-366/1986-007 was due to a defective drawing that did not show one electrical link. When a calibration procedure was written using the defective drawing, the electrical link that was missing from the drawing was not required to be opened (i.e., was always closed). Thus, when the procedure was performed, the isolation logic (since the link was closed) was capable of performing its function and the valve closed.

The cause of the events described in LER 50-366/1986-014 was personnel error. Maintenance personnel inadvertently left a rag in the HPCI lube oil sump after maintenance was performed. This rag prevented the lube oil system from functioning correctly and it prevented HPCI from being capable of performing its intended safety function. Additionally, another personnel error occurred during maintenance in that a cable was accidentally damaged such that when the HPCI was tested, an isolation of one of the HPCI PCIS valves occurred.

Corrective actions for these events included: 1) developing procedures, 2) performing calibrations, 3) generating an As Built Notice (ABN), 4) repairing damaged equipment, and 5) notifying maintenance personnel of the events and the consequences of the events.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
PLANT HATCH, UNIT 2	0 5 0 0 0 3 6 6	8 7	— 0 0 4 —	0 1	1 2 OF 1 2

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

The corrective actions for these events would not have prevented the event described in LER 50-366/1987-004 because the causes of the events were different. In the above previous events, the root causes for the events were defective drawings and personnel errors. In LER 50-366-1987-004, the causes of the events were defective procedures and personnel errors. While personnel errors occurred, the errors were made by different groups of personnel who performed different functions. Additionally, some of the personnel errors were performed by personnel who belong to other companies (off site vendor personnel).

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March 25, 1988

U. S. Nuclear Regulatory Commission
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PLANT HATCH - UNIT 2
NRC DOCKET 50-366
OPERATING LICENSE NPF-5
LICENSEE EVENT REPORT
PROCEDURE DEFECT AND PERSONNEL ERRORS
CAUSE SYSTEM INOPERABILITY AND ESF ACTUATIONS

Gentlemen:

In accordance with the requirements of 10 CFR 50.73(a)(2)(iv) and 10 CFR 50.73 (a)(2)(v), Georgia Power Company is submitting the enclosed, revised, Licensee Event Report (LER) concerning unanticipated actuations of an Engineered Safety Feature (ESF) and a condition where an ESF could have been incapable of performing its intended safety function. The events occurred in June of 1987 at Plant Hatch - Unit 2.

Sincerely,

L. T. Gucwa

LGB/lc

Enclosure: LER 50-366/1987-004 Rev 1

c: (see next page)

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Georgia Power

c: Georgia Power Company
Mr. J. T. Beckham, Jr., Vice President - Plant Hatch
GO-NORMS

U. S. Nuclear Regulatory Commission, Washington, D. C.
Mr. L. P. Crocker, Licensing Project Manager - Hatch

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