NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
NORTH ANNA POWER STATION, UNIT 2	0 5 0 0 0 3 3 9	1 OF 1 0

TITLE (4) INOPERABLE REDUNDANT S/G STEAM FLOW CHANNELS EXCEED TECHNICAL SPECIFICATION ACTION STATEME..T

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
1 1	0 4	8 7	8 7	0 1 5	0 1	0 2	0 3	8 8		0 5 0 0 0
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THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

OPERATING MODE (9): 1
POWER LEVEL (10): 0 2 7

[ ] 20.402(b)	[ ] 20.405(c)	[ ] 50.73(a)(2)(iv)	[ ] 73.71(b)
[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[ ] 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)	[X] 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)
E. Wayne Harrell, Station Manager	7 0 3 8 9 4 - 5 1 5 1

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)

[ ] YES (If yes, complete EXPECTED SUBMISSION DATE) [X] NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

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

On November 4, 1987, at 2153 hours, with Unit 2 in Mode 1 at 27 percent reactor power following a refueling outage, the "A" S/G Steam Flow Channel III and "B" S/G Steam Flow Channel IV were declared inoperable. The channels had not been declared inoperable within one hour of the first indications of potential inoperability. At 1200 hours on November 4, 1987, with Unit 2 in Mode 2 at 5 percent, the surveillance channel check recorded the same "A" and "B" S/G Steam Flow Channels to be outside of the acceptable tolerance limits. At 1816, with Unit 2 in Mode 1 at 24 percent, it was noted that the same "A" and "B" S/G Steam Flow Channels were still reading zero. The channels had not been declared inoperable at 1200 hours or at 1816 hours because the operators believed that the steam flow channel accuracy was unreliable at low power during start up following a unit outage. Technical Specification (T.S.) 3.3.1.1 and 3.3.2.1 require that during operation in Modes 1 through 3, a steam flow channel be placed in the tripped condition within one hour of determining it inoperable. This event is reportable pursuant to 10CFR50.73 (a)(2)(i)(B).

No safety consequences resulted from the inoperability of the "A" S/G Steam Flow Channel III or "B" S/G Steam Flow Channel IV. This is based on a safety evaluation which concluded that the plant was not operated in such a way as to invalidate the assumptions or results of any of the safety analysis presented in the applicable UFSAR Accident Analyses. As a result, the health and safety of the general public were not affected.

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1.0 Description of Event

On November 4, 1987, at 2153 hours, with Unit 2 in Mode 1 at 27 percent reactor power following a refueling outage, the "A" S/G Steam Flow Channel III (EIIS System Identifier SB, Component Identifier CHA) and "B" S/G Steam Flow Channel IV were declared inoperable. The channels had not been declared inoperable within one hour of the first indications of potential inoperability. At 1200 hours on November 4, 1987, with Unit 2 in Mode 2 at 5 percent, the surveillance channel check recorded the same "A" and "B" S/G Steam Flow Channels to be outside of the acceptable tolerance limits. At 1816, with Unit 2 in Mode 1 at 24 percent, it was noted that the same "A" and "B" S/G Steam Flow Channels were still reading zero. The channels had not been declared inoperable at 1200 hours or at 1816 hours because the operators believed that the steam flow channel accuracy was unreliable at low power during start up following a unit outage. Technical Specification (T.S.) 3.3.1.1 and 3.3.2.1 require that during operation in Modes 1 through 3, a steam flow channel be placed in the tripped condition within one hour of determining it inoperable. This event is reportable pursuant to 10CFR50.73 (a)(2)(i)(B) due to operating in a condition prohibited by the plant's Technical Specifications.

At 1200 hours on November 4, 1987, with Unit 1 in Mode 2 at 5 percent reactor power, during the surveillance channel check, the "A" S/G Steam Flow Channel III and "B" S/G Steam Flow Channel IV were recorded to be outside the acceptable tolerance limits. Operations noted on the channel check surveillance log that this was due to inaccuracies at low power levels. At 1719 hours on November 4, 1987, Unit 2 entered Mode 1 following a refueling outage. At 1816 hours, and at 24 percent reactor power, a Unit 2 Senior Reactor Operator log entry noted that the "A" S/G Steam Flow Channel III (FI-2474) and "B" S/G Steam Flow Channel IV (FI-2485) were reading zero. In addition, the "C" Loop Delta Temperature Control Channel III (TI-431B) reading was 10 percent low. This channel was removed from the auctioneering logics that utilize control Delta (T/Tavg) signals from each loop. The steam flow channels were not declared inoperable at 1200 hours or at 1816 hours because operators believed it was necessary to stabilize the unit at higher power levels before an accurate channel check could be performed to determine operability. Operations notified the onsite instrument technicians of the instrument channel problems at approximately 1816 hours, and requested the technicians to investigate.

At 1838 hours on November 4, 1987, another instrument channel, "B" Loop Delta (T/Tavg) Protection Channel II (TI-422A), was observed reading 10 percent low. Abnormal Procedure AP-3.0, "Loss of Vital Instrumentation", was entered. At 1904, the instrument technicians began investigations on the "B" Loop Delta (T/Tavg) Protection Channel II (TI-422A, EIIS Sytem Identifier IM, Component Identifier CHA). At 1915 hours, the "B" Loop Delta (T/Tavg) Protection Channel II was placed in the tripped condition as required by AP-3.4, "Loss of Vital Instrumentation Loop Delta T/TAVG". The instrument technicians continued trouble-shooting the "B" Loop Delta (T/Tavg) Protection Channel II for approximately three hours.

At 1900 hours operations began ramping at 4 percent reactor power per hour and at 1930 hours held the unit at 27 percent reactor power. At 2000 hours a second channel check found "A" S/G Steam Flow Channel III and "B" S/G Steam Flow Channel IV outside of the acceptable tolerance limits again. The operator who performed the channel check logged that this was being investigated.

At 2153 hours on November 4, 1987, at 27 percent reactor power, the "A" S/G Steam Flow Channel III and "B" S/G Steam Flow Channel IV were declared inoperable. The reason that the channels were not placed in the tripped condition at this time was due to Abnormal Procedure AP-3.7, "Loss of Vital Instrumentation Steam Flow". A note in AP-3.7 states that with the loss of any S/G Steam Flow channel coincident with any reactor coolant Loop Delta (T/Tavg) channel already in the tripped condition, "the plant must be placed in hot standby in 6 hours (T.S. 3.0.3)". Technical Specification (T.S.) 3.0.3 requires action within one hour to place the unit in hot standby within six hours if the Limiting Condition of Operation is not met. The note in AP-3.7 is very conservative because its purpose is to reduce the possibility of an inadvertent safety injection by initiating a voluntary shutdown rather than placing the failed instrument channels in the tripped condition. At 2200 hours on November 4, 1987, North Anna commenced a rampdown on Unit 2 in accordance with requirements of AP-3.7. Also, a "Notification of Unusual Event" (NOUE) was declared in accordance with the Emergency Plan Implementing Procedures. Notifications to State and local authorities were completed at 2216 hours, and the NRC was notified at 2240 hours.

At 2215 hours, the "B" S/G Steam Flow Channel IV was returned to service after an operator entered containment and shook the sensing lines near the transmitter (EIIS Component Identifier PT). This action resulted in accurate channel indication. The total elapsed time between the first recorded failed channel check and the time the "B" Channel IV was returned to service was approximately ten hours and fifteen minutes. The actual time of the failure is believed to have occurred before entry into Mode 3 (0905 hours on November 1, 1987) because no maintenance was performed on the circuit after entering Mode 3.

With the return of "B" Steam Flow Channel IV, it was decided to place the "A" Steam Flow Channel III in the tripped condition in compliance with T.S. 3.3.1.1 and 3.3.2.1, and thus, be able to exit from T.S. 3.0.3. It was necessary to make a temporary change to AP-3.7 to place the "A" S/G Steam Flow Channel III in the tripped condition coincident with the reactor coolant Loop "B" Delta (T/Tavg) Protection Channel II also being in trip. In support of this change, a safety analysis was performed in accordance with 10CFR50.59 which concluded that no unreviewed safety question existed. The Station Nuclear Safety and Operating Committee approved the procedure change prior to its use.

At 0012 hours on November 5, 1987, with the unit at approximately 18 percent power, the "A" S/G Steam Flow Channel III was placed in the trip condition in accordance with T.S. 3.3.1.1 and 3.3.2.1 allowing exit from T.S. 3.0.3 and the termination of the NOUE.

At 0220 hours on November 5, 1987, "A" S/G Steam Flow Channel III was returned to service. A measurement of the output voltage at the power supply card found the polarity reversed. The channel returned to normal when the error was corrected by reversing the input wiring to the process rack. The total elapsed time between the first recorded failed channel check and the time the "A" Channel IV was returned to service was approximately fourteen hours and twenty minutes. The time of the failure is believed to have occurred before entry into Mode 3 (0905 hours on November 1, 1987) because no maintenance was performed on the circuit after entering Mode 3.

At 0539 hours on November 5, 1987, the "B" Loop Delta Temperature protection channel was returned to service after calibration.

2.0 Safety Consequences and Implications

The Technical Specification requirements for a minimum number of redundant operable instrument channels in the reactor trip protection system (T.S. 3.3.1.1) and the Engineered Safety Feature Actuation System (ESFAS) (T.S. 3.3.2.1) are to ensure protection and mitigation of accident and transient conditions consistent with the assumptions in the accident analysis.

T.S. 3.3.1.1 requires steam flow indication input to the reactor protection system; however, the UFSAR takes no credit in the accident analysis for a reactor trip signal initiated by the presence of low S/G level in coincidence with with the steam flow greater than feedflow. (A Reactor Trip is initiated by the presence of one out of two steam/feedwater flow mismatch (greater than or equal to 40 percent of full steam flow) coincident with one out of two steam generator low level (less than or equal to 25 percent narrow range span).)

The purpose of this logic is to provide a backup for the Reactor Trip on steam generator low low level per IEEE Standard 279. Even considering the failures of both steam flow inputs to this protection circuitry, the criteria of the IEEE Standard was met by the remaining operable steam flow channels.

T.S. 3.3.2.1 requirement for steam flow input in the ESFAS is assumed in the accident analysis of the UFSAR. The UFSAR requires protection against the consequences of a Main Steam Line Break Accident from hot standby conditions to power operation. The concerns from a safety perspective for a steamline break are protection of the core from high local overpower conditions following the break, and overpressurization of the containment.

Automatic protection features for mitigation of steamline break include steamline isolation, which either terminates the steam release (for breaks downstream of the main steam trip valves (MSTV, EIIS System Identifier SB, Component Identifier V)) or limits the steam release to one steam generator (EIIS System Identifier SB, Component Identifier SG) for breaks upstream the MSTVs. Automatic safety injection (EIIS System Identifier BQ) provides RCS (EIIS System Identifier AB) pressure control and offsets the reactivity effects of RCS cooldown by injection of high concentration boric acid from the Boron Injection Tank (EIIS System Identifier CA, Component Identifier TK). Both safety injection and steamline isolation are initiated by the presence of one out of two high steamline flow signals in two out of three steamlines in coincidence with either a RCS Low-Low Tavg signal in any two RCS loops or a low steamline pressure signal in any two main steamlines.

There are diverse means of initiating both steamline isolation and safety injection (including manual initiations) which do not rely on steam flow indication. Steam line isolation occurs on intermediate high-high containment pressure (17.8 psia). Diverse safety injection occurs on high differential pressure (100 psi) between steam lines, high containment pressure (17 psia), and low-low pressurizer pressure (1765 psig).

Throughout this event, the other protection channels necessary for completing the logic to initiate a reactor trip or ESF actuation (Safety Injection) were operable or were placed in the tripped condition in accordance with T.S. 3.3.1.1 and 3.3.2.1. The Delta (T/Tavg) Protection Channel II was placed in the tripped condition within one hour of being outside the channel check acceptance criteria and of being declared inoperable. The redundant steam flow channels, "A" S/G Steam Flow Channel IV and "B" S/G Steam Flow Channel III, the Delta (T/Tavg) Protection Channels I and III, and both "C" S/G Steam Flow Channels were operable.

No safety consequences resulted from the inoperability of the "A" S/G Steam Flow Channel III or "B" S/G Steam Flow Channel IV. This is based on the conclusions of a safety evaluation performed to assess the impact of operating with a loss of one out of the two redundant steam flow channels on two out of three S/Gs for the core conditions at the time of this event.

The evaluation concluded that the plant was not operated in such a way as to invalidate the assumptions or results of any safety analyses presented in Chapters 6 and 15 of the UFSAR. The evaluation included a review of the capability to meet requirements of Regulatory Guide 1.97 (Post-Accident Monitoring and Diagnostics), Appendix R (Fire Protection), and 10CFR50.49 (as described within the guidelines of IEIN 84-90, Main Steam Line Break Effect on Environmental Qualification of Equipment). The conclusion was based on the following determinations:

1) The inoperable channels, while creating a reduction in redundancy, did not result in the potential loss of any safety function, even when assuming an additional single failure.

2) Even if the steam flow-related protection functions were postulated to be unavailable, diverse means of initiating safety injection and steamline isolation were available to adequately mitigate the effects of the entire spectrum of postulated steam line break events.

3) Core conditions at the time of this event precluded the occurrence of a post-trip return to power following even a worst case Main Steam Line Break Accident. The measured shutdown margin was significantly greater than the assumed shutdown margin used in the design basis analyses. Also, the moderator temperature coefficient was substantially less negative than the value assumed in the accident analysis, and within the allowable limits of Technical Specification 3.1.1.4.

4) Adequate information remained available to the operator at all times to perform any required post-accident monitoring, assessment, and mitigation as defined in the Emergency Operating Procedures.

As a result, the health and safety of the general public were not affected.

3.0 Cause of the Event

The root cause of this event was personnel error. The unit was operated outside of T.S. due to untimely operator decision to declare the channels inoperable, and inadequate use of alternate indications. The failure to detect the wiring error of the "A" Steam Flow Channel III was due to inadequate post-maintenance testing.

There were many contributing factors influencing the untimely operator action in declaring the channels inoperable. After stabilizing the unit from startup, attention was directed to the delta T/Tavg instrument failure. In addition, operations was concerned with minimizing the potential for an inadvertent safety injection when placing the failed steam flow channels in the tripped position. They determined that it would be acceptable to stabilize the unit before determining whether the steam flow channels reading zero were actually inoperable, since operations believed from past experience that the steam flow channels were inaccurate with low steam flow/low power conditions.

The cause of the "B" S/G Steam Flow Channel IV failure is unknown. The steam flow channel was returned to service after an operator entered containment and shook the sensing lines near the transmitter. This action resulted in accurate channel indication. A new transmitter (FT-2474) was installed during the last outage for corrective maintenance, and following installation a calibration was performed satisfactorily.

The failure of the "A" S/G Steam Flow Channel III was due to an error in the field wiring. The error was found during trouble-shooting when a measurement of the output voltage at the power supply card indicated the polarity was reversed. The channel returned to normal indication when the error was corrected by reversing the input wiring to the process rack. The cause of the wiring error has not been identified at this time. The most recent maintenance performed on this channel was to replace field Raychem splices.

Post-maintenance testing was thought to have been performed on FT-2474 following the repair work because it was recorded on the maintenance procedure (Engineering Work Request, EWR 87-206) that FT-2474 was tested. However, the test method was not documented with a test procedure. The test method used to functionally test FT-2474 is considered to be adequate. The functional test consisted of reading the output voltage at the loop power supply card locations with a digital voltmeter in order to determine if continuity and correct polarity existed. It is believed that the post-maintenance test did not detect the reversed polarity condition because the wrong loop power supply card was tested. The tagging record originally written for the "Raychem" repair was used to determine which power supply card locations to test and the wrong card location was written for FT-2474. The card location listed for FT-2474 was the card location for LT-2474, and when it was tested, it tested satisfactory.

4.0 Immediate Corrective Action

Upon determination that the "A" S/G Steam Flow Channel III and "B" S/G Steam Flow Channel IV were inoperable, immediate action was initiated to shutdown Unit 2 in a timely manner as conservatively required by AP-3.7. In addition, actions were started immediately to determine if AP-3.7 could be temporarily changed and if the failed channels could to placed in trip without initiating a safety injection. A containment entry was made to investigate the cause of the the "A" and "B" Steam Flow Channel inoperability. The "B" channel IV was returned to service within one hour of being declared inoperable. Unit rampdown was stopped when a change to the Abnormal Procedure was approved that would allow the "A" channel to be placed in the tripped condition.

5.0 Additional Corrective Actions

An Operations Directive was issued to provide interim guidance for assessing operability of steam flow channels at low power. It included the maximum power level for instrumentation response identification, an emphasis of the use of alternate indication, and the Technical Specification action statement for when the number of operable channels is less than the minimum required. In addition, the Shift Technical Advisor will utilize the Emergency Response Computer system to trend any parameters displaying indication problems during reactor start-up.

6.0 Actions Taken to Prevent Recurrence

The following corrective actions will be taken to prevent the possibility for recurrence of this event.

In order to minimize recurrence of failure to identify inoperable steam flow channels in a timely manner:

1) An updated Operations Directive providing final guidance for assessing operability of steam flow channels at low power was issued.

2) The Shift Technical Advisor will utilize the emergency response computer system to trend parameters displaying indication problems during reactor start-up.

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

3) Training for Operations personnel on this event will be provided in Licensing Operator Requalification Program (LORP) by station management and will include the studies and evaluations generated in response to this event on the reliability of steam flow indication at low power.

4) An evaluation will be performed to determine if instrument failure and indication problems can be incorporated into simulator startup scenarios.

5) Increased emphasis will be provided on the use of alternate indication during simulator scenarios.

6) A Human Performance Evaluation System (HPES) evaluation was performed to provide details concerning the untimely operator actions associated with declaring the steam flow inoperability. Recommendations from this report will be included in the review of this event that will be provided to operations through training.

In order to prevent recurrence of inadequate documentation of post-maintenance testing used to verify equipment operability following modifications, the post-maintenance test procedure development and documentation criteria will be reviewed and upgraded.

During the next unit outage of sufficient duration, when the field wiring is accessible, the "A" S/G Steam Flow Channel III wiring between the process rack and the transmitter will be inspected in order to determine the location of the reversed polarity.

In order to minimize recurrence of failures similar to that which caused the "B" Steam Flow Channel IV to rail, investigations as to the cause of the failure are continuing. These investigations will include an inspection by the Instrument Department on the transmitter, and its sensing lines. If the cause of the failure can be identified, corrective actions will be taken.

7.0 Similar Events

There have been no previously reported events for North Anna Power Station Units 1 or 2 involving failure of reactor protection and ESF instrumentation channels due to reversed wiring.

Four events involving steam flow channels failing low have been reported at North Anna Power Station Units 1 and 2. In one event, the channels were returned to service after repowering the transmitter by placing the master test switch in the "Test " position (Unit 1 LER 83-013). In one event, the channels failed due to instrument drift (Unit 2 LER 80-53). In one event, the channel failure was due to a loose connection on the transmitter (Unit 2 LER 80-027). In one event, the cause of the channel failure was unknown (Unit 1 LER82-039). One event was reported involving erratic steam flow channel indication with a zero reading on Unit 2 in Mode 1 (Unit 2 LER 81-002).

8.0 Additional Information

Unit 1 was in Mode 1 at 49 percent power and was unaffected by this event.

10 CFR 50.73

Vepco

VIRGINIA ELECTRIC AND POWER COMPANY
NORTH ANNA POWER STATION
P. O. BOX 402
MINERAL, VIRGINIA 23117

February 3, 1988

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

Serial No. N-87-041A
NO/KDT: nih
Docket No. 50-339

License No. NPF-7

Dear Sirs:

The Virginia Electric and Power Company hereby submits the following updated Licensee Event Report applicable to North Anna Unit 2.

Report No. LER 87-015-01

This report is being updated in response to NRC Inspection Report No. 50-339/87-38. This report has been reviewed by the Station Nuclear Safety and Operating Committee and will be forwarded to Safety Evaluation and Control for their review.

Very Truly Yours,

E. Wayne Harrell
Station Manager

Enclosure

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Mr. J. L. Caldwell
NRC Senior Resident Inspector
North Anna Power Station

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