NON-PUBLIC?: N
ACCESSION #: 9102080111
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Salem Generating Station - Unit 2 PAGE: 1 OF 11

DOCKET NUMBER: 05000311

TITLE: Reactor Trip - Loss of Both Steam Generator Feedwater Pumps Due To Inadequate PM
EVENT DATE: 06/28/90 LER #: 90-029-01 REPORT DATE: 01/30/91

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 075

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)
50.73(a)(2)(v)
50.73(a)(2)(vii)

LICENSEE CONTACT FOR THIS LER:
NAME: M. J. Pollack - LER Coordinator TELEPHONE: (609) 339-2022

COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: EA COMPONENT: XFMR MANUFACTURER: B455
REPORTABLE NPRDS: Y

SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT:

At 0032 hours on 6/28/90, during Salem Unit 2 power ascension operations, a reactor trip occurred following the loss of both Steam Generator Feedwater Pumps (SGFPs) resulting from failure of 2F 4160-480/277 Volt Transformer. Due to the loss of both SGFP's "Low Steam Generator Level Coincident with Steam Flow/Feed Flow Mismatch" had occurred causing the reactor trip. A main steamline isolation was manually initiated to reduce an excessive cooldown rate following the reactor trip. Main Steam Isolation Valves (MSIVs) 21 and 24MS167 did not close on the initial attempt; however,the operator again depressed the Main Steamline Isolation pushbuttons (this time for an extended period) and the valves closed. The unit was stabilized in Mode 3 (Hot Standby). The root cause of the transformer failure was inadequate preventive maintenance. The preventive maintenance program is being

revised to provide routine, documented inspection and cleaning of transformer coils. Also, the routine electrical transformer testing is being revised to include low frequency-induced test and corona detection to better check insulation and integrity for incipient failures. Investigation of the MSIV closure concern revealed the MSIV isolation logic did not meet design basis as per IEEE Standard 279. The MSIV circuitry was modified on Salem Units 1 and 2 to resolve the identified concerns. The MSIV design change concerns, addressed in this LER, have been reviewed by E&PB management and will be reviewed with applicable E&PB supervision stressing the importance of cross-disciplinary reviews of design changes.

END OF ABSTRACT

PLANT AND SYSTEM IDENTIFICATION:

Westinghouse - Pressurized Water Reactor

Energy Industry Identification System (EIIS) codes are identified in the text as {xx}

IDENTIFICATION OF OCCURRENCE:

Reactor Trip following the loss of both Steam Generator Feedwater Pumps; inadequate preventive maintenance

Event Date: 6/28/90

Report Date: 1/30/91

This report was initiated by Incident Report Nos. 90-438, 90-446 and 90-449.

CONDITIONS PRIOR TO OCCURRENCE:

Mode 1 Reactor Power 75% - Unit Load 700 MWe

DESCRIPTION OF OCCURRENCE:

On June 28, 1990 at 0032 hours, during power ascension operations, a reactor trip occurred on No. 24 Steam Generator low level coincident with a steam flow/feed flow mismatch as a result of the loss of both Steam Generator Feedwater Pumps (SGFPs). The loss of the SGFPs was preceded by failure of the 2F bus 4160-480/277 Volt Transformer {EA}.

The transformer failure resulted in the loss of No. 24 MAC (Miscellaneous AC) Panel. This panel feeds No. 22 SGFP governor and controls; consequently, the actual SGFP speed defaults to zero rpm, although the SGFP does not actually trip. The Control Room bezel indication for the SGFP will still indicate the pump as "latched" and operating at approximately 3750 rpm.

At the time, No. 21 SGFP was being lubricated via No. 21B SGFP Lube oil Pump. This motor-driven pump also receives its power via the 2F bus 4160-480/277 Volt transformer; therefore, upon loss of the transformer, the lube oil pump stopped. The backup pump No. 21A then started.

Bearing oil pressure had decreased to less than ten psig (the SGFP lube oil pump discharge header low pressure trip setpoint) during the lube oil pump swap and did not increase above ten psig prior to the time delay relay timing out. Consequently, No. 21 SGFP tripped on "Low Feedpump Bearing Oil Pressure". Upon loss of the No. 21 SGFP (approximately 27 seconds after the transformer failure), operations personnel initiated a turbine runback. A manual reactor trip was not initiated as it was believed No. 22 SGFP was still operating.

Due to the loss of both SGFP's, an automatic reactor trip on "Low

DESCRIPTION OF OCCURRENCE: (cont'd)

Steam Generator Level Coincident with Steam Flow/Feed Flow Mismatch" occurred.

The plant cooldown was greater than anticipated for a reactor trip from 75% power. Pressurizer level and pressure decreased to 9% and 1980 psig, respectively. Prior to the trip, Pressurizer level was 43% and Pressurizer pressure was 2240 psig.

In response to the excessive cooldown, a main steamline isolation {JE} was manually initiated (from both trains), per the Emergency Operating Procedure. After initiating the isolation, it was noted that Nos. 21 and 24MS167 Main Steam Isolation Valves (MSIVs) did not indicate closed. The operator initiated the main steam isolation again by depressing the pushbuttons (this time for an extended period) and received a closed indication for the subject MSIVs.

After completion of the main steamline isolation, the Unit was

stabilized in Mode 3 (Hot Standby). On June 28, 1990 at 0207 hours, the Nuclear Regulatory Commission (NRC) was notified of the automatic actuation of the Reactor Protection System and the initiation of Main Steamline Isolation (an Engineered Safety Feature), in accordance with the Code of Federal Regulations (CFR) 10CFR 50.72 (B) (2) (ii). Also, on June 29, 1990 at 0229 hours, the NRC was notified of the concern with the manual main steamline actuation circuitry, in accordance with 10CFR 50.72 (b) (2) (iii).

APPARENT CAUSE OF OCCURRENCE:

The reactor trip resulted from failure of the 2F 4160-480/277 Volt Transformer. The root cause of the transformer failure is attributed to inadequate preventive maintenance.

Approximately one week prior to this event, the Salem Unit 1 1H 4160-480/277 Volt Transformer (a non-1E transformer) had also failed. This is the same type transformer as the subject 2F transformer. Initial investigation of the Unit 1 transformer showed evidence of a phase to ground fault similar to the 2F transformer.

Detailed inspections and electrical laboratory testing, of the 2F and the 1H transformers, revealed the fault in each transformer occurred on the transformer High Voltage (HV) side, with the failure confined to a coil (winding) located at one end of the transformer assembly. This was evidenced by burned insulation, phase-to-ground arcing, and massive collapse of the outer layers of the HV winding. In addition, the bolts on the transformers' HV (4160V) lead support structure in the vicinity of the coil failure had indications of fusing and the transformers' grounding straps also showed evidence of arcing and fusing.

Disassembly and electrical testing of the 2F and 1H transformers revealed the cooling ducts between the transformers' windings were

APPARENT CAUSE OF OCCURRENCE: (cont'd)

contaminated with dust composed of fine "hair-like" fibers. These airborne conducting contaminants created voltage stresses, which resulted in degradation of the transformer winding insulation and eventual breakdown across the HV winding cooling duct.

Existing transformer preventive maintenance requirements (performed every eighteen months), specify cleaning the cabinets; however, they

do not specify detailed cleaning of the winding air flow passages or the transformer cubicle. As a result, dust buildup occurred within the transformer. This dust accumulation was not identified since it was located in not normally visible locations. Vendor recommended maintenance (i.e., transformer technical manual) does not detail the cleaning requirements.

A contributing factor to this event was an incorrect setting of the Agastat timing relay, used for delaying the arming of the "Low Feedpump Bearing Oil Trip". It had been set for two instead of the required five seconds. The time delay is designed to prevent inadvertent actuation of the feedpump trip circuit during swap over from the in-service lube oil pump to the backup lube oil pump. Had the relay been set correctly, the No. 21 SGFP should not have tripped and a Unit trip should have been averted since the Unit was operating at 75% power. The root cause of the incorrect relay setting is personnel error. The calibration procedure for setting the relay setpoint requires the use of a print, which specifies the setpoint as five seconds.

Contributing to the low oil pressure trip of No. 21 SGFP was a design concern. The SGFP lube oil system design includes a pressure equalizing line between the discharges of the SGFP Lube Oil Pumps. This line mitigates the potential for a loss of "prime"; however, investigation revealed this equalizing was not installed.

FAILURE DATA:

2F 4160-480Y/277 Volt Transformer

Manufacturer: Brown Boveri (formally ITE)
Model: Dry Type
Rating: 1000/1333 KVA

ANALYSIS OF REACTOR TRIP EVENT:

The trip on low Steam Generator level (25%) coincident with steam flow/feed flow mismatch is an anticipatory trip to prevent a loss of heat sink by sensing conditions which would eventually result in a dry steam generator. By tripping the reactor prior to reaching the low-low level setpoint in the steam generator, the required starting time and capacity requirements for the Auxiliary Feedwater System {BA} are reduced and the thermal transient in the Reactor Coolant System {AB} and steam generator are minimized.

ANALYSIS OF REACTOR TRIP EVENT: (cont'd)

The excessive cooldown has been attributed to two factors:

1. All three (3) Auxiliary Feedwater (AFW) Pumps (2 motor driven and 1 steam driven) were operating, and

2. Low core decay heat levels due to the recent completion of a refueling outage.

The motor driven and turbine driven AFW Pumps started, per design, upon loss of main feedwater and all four (4) Steam Generators had reached the low-low level setpoint. With all three (3) AFW Pumps operating, approximately twice the design basis flowrate to the Steam Generators was realized (8.8E5 lb sub m/hr instead of 4.4E5 lb sub m/hr). The Turbine Driven Pump is designed to supply 100% flowrate and the Motor Driven Pumps are designed to provide 50% flowrate each.

As the event involved an automatic actuation of the Reactor Protection System, it is reportable in accordance with 10 CFR 50.73 (a) (2) (iv).

ANALYSIS OF MSIV CONCERN:

As reflected in the Description of Occurrence section, Nos. 21 and 24 MS167 valves did not indicate closed following the first attempt at manual initiation of main steamline isolation. Subsequent investigation verified the valves did not close on the initial closure attempt. The problem was traced to the control circuit logic design. To ensure closure, either the MS167 valves open limit switch must be "made up", or the safeguards actuation signal must be present until the closed limit is reached. The Nos. 21 a
d 24 MS167 valves
had drifted from their open position prior to the isolation attempt. Therefore, when the bezel pushbuttons were not held in for a sufficient time on the first attempt at Main Steam Isolation, the valves did not close.

The cause of Nos. 21 and 24 MS167 valves drifting from their full open position is attributed to spring loaded detent mechanisms on the valves not being fully engaged, and broken detent mechanisms on both valves. Inspections revealed the valves' limit switches were set short of full open, attributed to a lack of procedural guidance for defining the appropriate limit switch position. Consequently, the detent mechanisms did not engage and the valves drifted open. The

detent mechanisms for the other Unit 2 MS167 valves were inspected with no other problems identified.

During subsequent power operation, the No. 21MS167 valve periodically drifted off its full open limit. When this occurs, the valve is repositioned to full open. The cause of the No. 21MS167 valve drift is suspected to be valve packing deterioration. The presently installed packing has a design service life of thirty-six (36) months, and has been in service for approximately eighteen (18)

ANALYSIS OF MSIV CONCERN: (cont'd)

months. The valve packing concern will be addressed at the next outage in which the Unit enters Mode 4 (i.e., Maintenance Outage).

As previously identified, a main steam line isolation signal is not sealed-in unless the valve is in the fully open position. This design did not meet the intent of the criteria for protective actuation signals, specified by IEEE Standard 279, "Proposed IEEE Criteria For Nuclear Power Plant Protection Systems" (dated August 30, 1986), which is committed to via the Updated Final Safety Analysis Report (UFSAR) section 3.1.2. The standard states:

"...the protection system shall be so designed that, once initiated, a protective action at the system level shall go to completion."

The circuitry concern was not previously identified, and two MS167 valves failed to close upon initial receipt of a valid closure signal by the operator; therefore, this event is reportable in accordance with 10CFR50.73 (a) (2) (v) and 10CFR50.73 (a) (2) (vii).

To correct the above MS167 valve design concern, a design change was implemented on July 4, 1990. This design change (DCP 2EC-3031) revised the controls circuit wiring to ensure seal-in of a closure signal (automatic or manually initiated) to a MSIV even if the subject valve had drifted off its full open limit. Specifically, circuit positions of the MSIV control logic 74-1 relays "operate" and "reset" coils were interchanged such that all "normally open" contacts of the relays were changed to "normally closed" and all "normally closed" contacts were changed to "normally open". On July 9, 1990, (with the Unit in Mode 2 at 1% reactor power) MS167 valve operability testing identified that as a result of implementation of DCP 2EC-3031, an uncontrolled main steam leak path existed via the

MS167 pressure chamber orifice through the three way valve (MS168) and to the open solenoid operated vent valves. Subsequently, Unit 2 was taken to Mode 4 (Hot Shutdown).

One of the design base accidents plant design must mitigate is a Steam Generator Tube Rupture (SGTR) event. Since the Emergency Operating Procedures (EOPs), which address required operator actions during an SGTR event, did not require resetting the 74-1 relays, it was determined that this design basis was not met. Therefore, in accordance with Code of Federal Regulations 10CFR 50.72 (B) (1) (ii) (B), the Nuclear Regulatory Commission was notified of this event on July 9, 1990 at 1948 hours.

The inadequacy of DCP 2EC-3031 is attributed to lack of a cross disciplinary review during development of the proposed design change. This occurred when Mechanical engineers were not included in the review/approval of the design modification. During development of the design change, it was incorrectly perceived the change only affected the electrical design of the MSIV. Therefore, as a result of personnel error (i.e., Engineering & Plant Betterment (E&PB)

ANALYSIS OF MSIV CONCERN: (cont'd)

management oversight), only electrical engineers were involved in the design modification. Consequently, the subject of a possible uncontrolled main steam release pathway (which occurred when an MSIV was closed during operability testing) went unrecognized during review and implementation of the design change.

Westinghouse analysis PSE-90-660, NS-OPLS-OPL-II-90-538, dated July 30, 1990, "Safety Evaluation for Potential Leak Path (Steam) from MSIVs" provided a determination of the impact to the offsite doses of any increase to the amount of steam released to the atmosphere from a Steam Generator Tube Rupture (SGTR) event. Specifically, this was performed to consider the effect of operation with a steam flow path through the MSIV pressure chamber orifices to the atmosphere.

For the Salem Unit 2 analysis, the amount of radioactivity released to the atmosphere from the failed steam generator was conservatively based upon the total activity associated with the calculated primary to secondary break flow and was assumed to be independent of the amount of steam released to the atmosphere from the ruptured steam generator. It was determined the atmospheric steam flow through the MSIV flow path would not affect the assumption that the break flow

can be terminated within 30 minutes since Emergency Operating Procedure transition would not occur due to an uncontrolled Secondary Containment depressurization.

Results of the radiological evaluation indicate that due to the installation of DCP 2EC-3031 the offsite doses, reported in the Salem Unit 2 SGTR event, could have increased; however, they would have remained well within the NRC 10CFR100 guidelines. Based upon this, the Salem Unit 1 and 2 licensing basis safety analyses and conclusions as described in the Salem FSAR remain valid and the consequences of a SGTR event were not increased as a result of the installation of DCP 2EC-3031.

When it was recognized that a main steam release path existed after fast closure of the MSIVs, due to installation of DCP 2EC-3031, a new design change (2EC-3035) was developed and installed. This design change restored the Unit 2 MSIV fast closure circuitry to the configuration existing previous to implementation of DCP 2EC-3031. In addition, it ensures that the 74 relay "operate" coils will remain de-energized until the MSIV is fully closed, thereby sealing-in any initiation signal to the MSIVs regardless of the duration of that signal (see Reference Drawings section). To upgrade the design of the Unit 1 MSIV actuation circuitry and thereby ensure valve closure, the design change installed on Unit 2, per DCP 2EC-3035, was also implemented on Unit 1 in accordance with DCP 1EC-3032.

CORRECTIVE ACTION

In response to the transformer failures, an Operations surveillance requirement, to check and record 1E (Vital) and non-1E (non-Vital) transformer operating temperatures and verify proper transformer

CORRECTIVE ACTION: (cont'd)

operation, was incorporated into "Primary" and "Secondary" plant log Operations Directive Procedures (OD)-26 and 27, respectively.

Operations Department Administrative Directive AD-44, "Emergency Operating Procedure Program Maintenance" was revised to address the concerns associated with excessive cooldown after a reactor trip where all three AFW pumps start. The AD now provides an option to reduce Auxiliary Feedwater flow, after completion of "immediate actions" per the Emergency Operating Procedure, by throttling down to no less than 22E4 lb sub m/hr flowrate. An Engineering review of the

required AFW System capacity was previously initiated due to similar cooldown rates experienced following reactor trips.

Operations procedure III 11.3.1 has been revised to require the 21A and 22B SGFP Lube Oil Pumps be the primary oil pumps and the 21B and 22A pumps as the emergency backup pumps. This prevents the loss of lube oil to both SGFPs upon loss of a single electrical transformer.

The calibration procedure for the low oil pressure trip of the SGFP lube oil pumps has been revised to include calibration of the associated Agastat time delay relays in accordance with the applicable print.
Design changes have been implemented on Salem Units 1 and 2 to install equalizing lines between the respective discharge lines of the designated primary and backup SGFP lube oil pumps.

The No. 21MS167 and No. 24MS167 valve detents were repaired as required. All the other detents (for all four MS167 valves) were inspected with no other problems identified.

A preventive maintenance program for MS167 valves has been established. This program consists of scheduled valve repacking, hydraulic system cleaning, hydraulic oil changes, and detent and limit switch inspection, lubrication, and adjustment.

This event has been reviewed by the PSE&G Nuclear Training Department. Applicable training programs have been upgraded to address lessons learned.

Based upon engineering analysis of the transformer failures, the following corrective actions are being implemented:

1) Revision of the preventive maintenance program (with applicable procedure changes) to provide routine, documented inspection and cleaning of transformer coils.

2) Revision of routine electrical transformer testing to include low frequency-induced test and corona detection to better check insulation and integrity for incipient failures. In addition, revision of these tests will include adjustment of the transformer power factor test voltage to the appropriate level.

CORRECTIVE ACTION: (cont'd)

This event has been reviewed by E&PB management and will be reviewed with applicable E&PB supervision stressing the importance of cross-disciplinary reviews within the DCP program.

General Manager -
Salem Operations

MJP:pc

SORC Mtg. 91-003

TEXT PAGE 10 OF 10

Figure "REFERENCE DRAWINGS: 1. Schematic of original MSIV closure circuit design" omitted.

TEXT PAGE 11 OF 11

Figure "REFERENCE DRAWINGS: (cont'd), 2. Schematic of final modified MSIV closure circuit design" omitted.

ATTACHMENT 1 TO 9102080111 PAGE 1 OF 1

PSE&G
Public Service Electric and Gas Company
P. O. Box 236 Hancocks Bridge, New Jersey 08038

Salem Generating Station

January 30, 1991

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Dear Sir:

SALEM GENERATING STATION
LICENSE NO. DPR-75
DOCKET NO. 50-311
UNIT NO. 2
LICENSEE EVENT REPORT 90-029-01; SUPPLEMENT

This Supplemental Licensee Event Report is being submitted pursuant to the requirements of 10CFR 50.73. This supplement addresses the

identification of the reactor trip root cause and applicable corrective actions. Also, completed analysis of the main steamline isolation valve concerns (identified subsequent to the reactor trip) is addressed.

Sincerely yours,

S. LaBruna
General Manager -
Salem Operations

MJP:pc

Distribution

The Energy People

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