PSE&G

Public Service Electric and Gas Company P.O. Box E Hancocks Bridge, New Jersey 08038

Salem Generating Station

July 7, 1989

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

Dear Sir:

SALEM GENERATING STATION
LICENSE NO. DPR-70
DOCKET NO. 50-272
UNIT NO. 1
LICENSEE EVENT REPORT 89-024-00

This Licensee Event Report is being submitted pursuant to the requirements of the Code of Federal Regulations 10CFR 50.73(a)(2)(iv). This report is required within thirty (30) days of discovery.

Sincerely yours,

L K Miller / pw

L. K. Miller
General Manager -
Salem Operations

MJP:pc

Distribution

IE22
1/1

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)
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TITLE (4)

Safety Injection/Rx Trip During Mode 3 Operation Due To Inadequate Procedures

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 5 0 0 0
0 6	0 9	8 9	8 9	— 0 2 4	— 0 0	0 7	0 7	8 9		0 5 0 0 0

OPERATING MODE (9): 3

POWER LEVEL (10): — — —

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)	[ ] 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)
M. J. Pollack - LER Coordinator	6 0 9 3 3 9 - 4 0 2 2

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	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 6/9/89, with the Unit in Hot Standby (Mode 3), a Safety Injection (SI) concurrent with a Reactor Trip signal occurred. The trip signal and SI were the result of High Steamline Delta P caused by the No. 13MS15 Main Steam (MS) Safety Valve lifting. Prior to this event, post outage control rod surveillance testing was in progress using procedure SP(O)4.1.3.1.2. Shutdown Bank "A" was out to step 228. Additionally, the S/Gs were being fed from the Auxiliary Feedwater System. The Steam Generator Feedwater Pumps were not latched. All parts of the reactor protection system and SI logic functioned as designed upon receipt of the SI/trip signal. The root cause of this event has been attributed to inadequate drainage of the main steamlines caused by either of two factors: 1) inadequate procedures and 2) a failure to comply with station Administrative Procedures (APs) by plant personnel in 1987. This event will be reviewed with applicable Maintenance Department and Technical Department personnel. The need to comply with AP programs in their entirety will be stressed. Procedures have been modified to place the steam trap system in service when the plant enters Mode 4 (from Mode 5). As stated in the Analysis of Occurrence section, the main steamline safety valves were tested and reset, as applicable. The previously unidentified globe valve has been numbered and added to TRIS. Westinghouse has initiated a review and analysis of this event. Engineering investigation of the main steam safety valve setpoint concern identified as a result of this event is continuing.

PLANT AND SYSTEM IDENTIFICATION:

Westinghouse - Pressurized Water Reactor

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

IDENTIFICATION OF OCCURRENCE:

Safety Injection/Reactor Trip During Mode 3 Operation Due To Inadequate Procedures

Event Date: 6/09/89

Report Date: 7/07/89

This report was initiated by Incident Report No. 89-329.

CONDITIONS PRIOR TO OCCURRENCE:

Mode 3 (Hot Standby)

DESCRIPTION OF OCCURRENCE:

On June 9, 1989 at 1641 hours, with the Unit in Hot Standby (Mode 3), a Safety Injection (SI) concurrent with a Reactor Trip signal occurred. The trip signal and SI were the result of High Steamline Delta P caused by the No. 13MS15 Main Steam (MS) Safety Valve {SB} lifting.

Prior to this event, post outage control rod surveillance testing was in progress using procedure SP(O)4.1.3.1.2. Shutdown Bank "A" was out to step 228. Additionally, the S/Gs were being fed from the Auxiliary Feedwater System. The Steam Generator Feedwater Pumps were not latched. All parts of the reactor protection system and SI logic functioned as designed upon receipt of the SI/trip signal.

The Unit was stabilized in Mode 3, and in accordance with the requirements of the Code of Federal Regulations 10CFR 50.72(b)(2)(ii), the Nuclear Regulatory Commission was notified of the automatic actuation of the Emergency Core Cooling System (ECCS) {JE}. This was the seventeenth SI actuation cycle to date.

APPARENT CAUSE OF OCCURRENCE:

The root cause of this event has been attributed to inadequate drainage of the main steamlines caused by either of two factors: 1) inadequate procedures and 2) a failure to comply with station Administrative Procedures (APs) by plant personnel in 1987.

Operation Department procedures did not require the MS7 valves ("Main Steam Drain Valves) to be open during Modes 3 and 4. The opening of the valves allows drainage of condensate upstream of the MS167 valves

APPARENT CAUSE OF OCCURRENCE: (cont'd)

("Main Steam Stop Valves"). This condensate would build up in the main steamline which could lead to this event (as explained below).

Subsequent to this event, a previously unidentified globe valve was discovered. During the 7th refueling outage, in early 1987, this valve was added to the main steam system drain line just upstream of the No. 12 Condenser. Since this unknown valve was closed, flow to the Condenser would not have occurred even with the MS7 valves open. The unauthorized installation of this valve is contrary to the requirements of Administrative Procedure (AP) AP-8, "Design Change Test and Experiment Program" which states that a DCR is required for any design change involving a print revision.

Water from the four main steamlines' is drained through steam traps. These lines join in a single header which enters the No. 12 Condenser. The valve was added in conjunction with the replacement of piping and was to function as an isolation valve in support of any future related work. Therefore, with this valve closed, no drainage to the No. 12 Condenser could occur. Operations was not informed of the installation of the valve; therefore, the computerized Tagging Request Information System (TRIS) was not updated to identify the existence of the valve.

As indicated above, investigation revealed that the main steamlines contained a significant amount of water at saturated temperature. In the No. 13 main steamline, this saturated water underwent oscillating wave phenomenon by changing to steam and back to water resulting in steamline steam/water mixture density changes. These density wave oscillations took the form of pressure spikes resulting in safety valve 13MS15 lifting twice and the resulting SI on differential pressure. After lifting the first time, the valve reseated. However, due to the decrease in steamline pressure due to this first lift, the remaining saturated water in the line flashed to steam resulting in the valve's second lift. Water and steam were observed to exhaust from the valve.

Approximately five (5) minutes prior to the first safety valve lift, No. 13 S/G blowdown was initiated. This may have caused the initiation of the oscillating wave phenomenon.

The review of available data indicate that No. 13 S/G steam flow channel experienced spikes of 28% and 46%, from an initial indicated signal of 7.5%, occurred. This corroborates indications that the safety valve lifted twice.

ANALYSIS OF OCCURRENCE:

The reactor trip signal was generated as a result of the safety injection signal. Normally, the trip signal is provided to protect the core in the event of a LOCA, assuming a trip signal was not already generated from other logic sources.

ANALYSIS OF OCCURRENCE: (cont'd)

The SI signal on high differential pressure (> 100 psig) between steamlines is designed to detect a steamline break and mitigate the subsequent large positive reactivity insertion in the core due to the reduction in T_{ave}. The SI signal was the result of the oscillating wave phenomenon as discussed in the Apparent Cause of Occurrence section.

After the event, main steamline pipe temperatures were taken. Temperature differences between the piping top and bottom for the four steamlines indicate the lines were approximately 30 - 40% full of saturated water. Temperature readings showed the bottom of steam pipes to be up to 130°F below the top of the pipes. Upon opening the MS7 valves, the previously unidentified globe valve (just upstream of the No. 12 Condenser) and the MS924 vent valve the steamline temperatures equalized.

After the event, the 13MS15 main steamline safety valve was lift set tested. It lifted at 1053 psig, which is 6 psig below its setpoint acceptance value. The valve was reset and retested satisfactorily. The setpoint variance may have contributed to the premature opening of the 13MS15 valve. No safety significance is attributed to this variance. The remaining nineteen main steamline safety valves were tested. Nine of these valves were similarly below their setpoint acceptance value. These valves were also reset and retested satisfactorily. It is suspected that the reason the valve setpoints were found lower than the manufacturer set value is because the installed valves are exposed to high ambient temperature from the Main Steam System piping which increases the spring temperature and lowers the valve setpoint. These valves are new (installed during the current refueling outage). Their lift setpoints are factory set using a steam lift bench test, but the bench test does not allow the spring to heat up to a temperature equivalent to actual plant ambient conditions.

During this event, the No. 12 Auxiliary Building Exhaust Fan tripped after receipt of an SI start signal. It also tripped on a manual start attempt.

The No. 12 Auxiliary Building Exhaust Fan 460 V breaker was retested in accordance with procedure M3Q, "230 and 460 Volt K-Series Breaker Overload Test". The as-found "300% trip time" was approximately 9 - 10 seconds compared to the acceptance range of 7 to 35 seconds. The breaker setting was adjusted to the high end of the range (i.e., 25 to 35 seconds), retested and returned to service. Due to the high in-rush current, unique to large fan motor starts, the setting of this breaker trip setpoint to the low end of the acceptance range would not guarantee a start in all conditions.

Additionally, the "B" Reactor Trip Shunt Relay actuation did not print out on the Sequence Of Events (SOE) recorder. The Shunt Relay "B" Trip actuation capability was tested several times after the SI/trip. It successfully actuated after each test. It has been

ANALYSIS OF OCCURRENCE: (cont'd)

determined by PSE&G engineering that the relay did function during the event, however, its functioning was not recorded due to the speed of the initiating event. Either the relay did not completely de-energize or the relay did de-energize but did not do so long enough for the SOE recorder to record it. The "A" Reactor Trip Shunt relay de-energization was recorded on the SOE recorder. It cleared on the recorder in approximately one cycle (16 mseconds) which indicates that the event was very fast. The "B" reactor trip breaker did open automatically due to the event.

The high differential pressure between steamlines trip/SI is designed to mitigate transients from full power. Since this event occurred in Mode 3 the affect(s) on the plant were minimal. This event did not affect the health or safety of the public; however, it is reportable, in accordance with Code of Federal Regulations 10CFR50.73(a)(2)(iv), due to the automatic actuation of the Reactor Protection System and an Engineered Safety Feature.

CORRECTIVE ACTION:

This event will be reviewed with applicable Maintenance Department and Technical Department personnel. The need to comply with AP programs in their entirety will be stressed.

Procedures have been modified to place the steam trap system in service when the plant enters Mode 4 (from Mode 5). The main steamline safety valves testing was not initiated until this procedure was used.

As stated in the Analysis of Occurrence section, the main steamline safety valves were tested and reset, as applicable.

The previously unidentified globe valve has been numbered and added to TRIS. It is now identified in TRIS as "normally open". A design change package has been initiated which will establish the appropriate administrative design configuration contol for the globe valve.

The M3Q procedure has been revised to set the Auxiliary Building Exhaust and Supply Fans 460 V breakers trip setpoint to the high end (25 - 35 seconds) of the acceptance range (7 - 35 seconds). The No. 12 Auxiliary Building Exhaust Fan breaker has been set to the high end of the acceptance range and has been returned to service. The other 460 V fan motor breakers will be tested and reset as applicable.

Westinghouse has initiated a review and analysis of this event.

Engineering investigation of the main steam safety valve setpoint concern is continuing.

POST SAFETY INJECTION DATA:

Initial Pressurizer Level	26%

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POST SAFETY INJECTION DATA: (cont'd)

Final Pressurizer Level	69%
Initial Pressurizer Pressure	2235 psig
Final Pressurizer Pressure	2235 psig*
Initial Average Reactor Coolant Temperature	548° F
Final Average Reactor Coolant Temperature	536° F*
Refueling Water Storage Tank Temperature	80° F
Duration of Safety Injection	11 minutes

L K Miller /pw
General Manager -
Salem Operations

MJP:pc

SORC Mtg. 89-071