PSE&G

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

Salem Generating Station

August 25, 1982

Mr. R. C. Haynes
Regional Administrator
USNRC
Region 1
631 Park Avenue
King of Prussia, Pennsylvania 19406

Dear Mr. Haynes:

LICENSE NO. DPR-75
DOCKET NO. 50-311
REPORTABLE OCCURRENCE 82-04/03X-1
SUPPLEMENTAL REPORT

Pursuant to the requirements of Salem Generating Station Unit No. 2 Technical Specifications, Section 6.9.1.9 b, we are submitting supplemental Licensee Event Report for Reportable Occurrence 82-04/03X-1.

Sincerely yours,

H. J. Midura

H. J. Midura
General Manager -
Salem Operations

RH:ks

CC: Distribution

Report Number: 82-04/03X-1

Report Date: 08-25-82

Occurrence Date: 01-14-82

Facility: Salem Generating Station, Unit 2
Public Service Electric & Gas Company
Hancocks Bridge, New Jersey 08038

IDENTIFICATION OF OCCURRENCE:

DNB Parameters - Exceeded Specification Limits.

This report was initiated by Incident Report 82-012.

CONDITIONS PRIOR TO OCCURRENCE:

Mode 1 - Rx Power 97% - Unit Load 1060 MWe.

DESCRIPTION OF OCCURRENCE AND APPARENT CAUSE:

On January 14, 1982, reactor power was at 97% with a corresponding generator load of 1060 MWe gross. The Condensate Polishing System (CPS) was in service and the Steam Generator Feed Pump (SGFP) suction pressure was 330-340 psig.

At 0105 hours, a secondary system disturbance associated with the No. 2A Feedwater Heater and Moisture Separator Reheater Drain Tank Level Control System caused the SGFP suction pressure to start decreasing.

At 0106 hours, the temporary 300 psig alarm installed for the Nos. 21 and 22 SGFP's suction pressure started going into and out of the alarm condition and a few seconds later annunciated in a solid alarm condition. The SGFP suction pressure was less than 300 psig.

The Control Operator responded by manually initiating a turbine load reduction, made in short, 2-3 second intervals. In conjunction with the manually initiated load reduction, the operator also initiated actions to bypass the Condensate Polishing System (CPS). Both of the above actions were taken in an attempt to stop the SGFP suction pressure from decreasing to the SGFP low suction pressure trip set point of 215 psig. Additionally, an attempt was made to manually insert the control rods in order to offset the increase in Reactor Coolant System (RCS) average temperature (Tave) caused by the load reductions. However, the attempt to insert the rods resulted in an urgent failure alarm in the Rod Control System. It was due to a failure of the firing circuit control card in a control bank D power cabinet. Due to the urgent failure the Rod Control System placed a "HOLD SIGNAL" on all the control rods stationary grippers for the rods controlled by that power cabinet. The operator then manually initiated RCS boration at approximately 10 gpm in an attempt to reduce RCS Tave.

At 0107 hours, the temporary alarm for the No. 21 and 22 SGFP's low suction pressure cleared when the bypassing of the CPS was completed (CPS bypass valves 21, 22 & 23 CN108's fully open). The alarm remained clear for a short period, then re-annunciated. The SGFP suction pressure at the time was 240-260 psig and decreasing. The cause was flashing in the Feedwater Heater and Moisture Separator Reheater Drain Tanks, which was due to the reduced pressure in the drain tanks. The pressure was decreasing since turbine load was being decreased which correspondingly caused extraction steam pressure to decrease, and feedwater heater and feedwater heater drainage pressure to decrease. The drain tank flashing caused discharge pressure and flow on the heater drain pumps to decrease, which caused SGFP suction pressure to decrease.

At 0108 hours, the SGFP low suction pressure alarm again cleared, however, the high steam flow alarms for all steam generators on the control console bezels and also on the Reactor Protection System logic display panel (2RP4) annunciated.

The cause of the high steam flow alarms was the opening of the condenser steam dump valves. The Condenser Steam Dump System had been armed in the load rejection mode of operation as a result of the turbine load reduction. When RCS Tave exceeded the programmed reference temperature (Tref) by 5°F, the steam dumps began modulating to control Tave at 5°F above Tref. It was noted that at this time 8 steam dump valves were full open and the remaining 4 valves were throttling. Note that the high steam flow alarm set point is a programmed set point which is programmed at 40% steam flow from 0-20% of reactor power and ramps linearly to 110% steam flow as turbine power increased to 100%. Since the program ramp is developed from turbine first stage pressure, as turbine load was reduced the high steam flow alarm set point was being ramped down. At no time during the transient did steam flow exceed 100%.

At 0109 hours the SGFP low suction pressure alarm again annunciated. At this time turbine load was 230 MWe and reactor power was 90% and a mismatch of about 70% between turbine load and reactor power existed. This power mismatch was being rejected to the condensers by the Steam Dump System. RCS Tave was approximately 580°F and was maintained at that point by the modulation of the steam dump valves.

When the Senior Shift Supervisor entered the Control Room and noted the large mismatch between reactor power and turbine load, he immediately ordered the operators to start increasing turbine load to reduce the power mismatch and allow the steam dumps to close. As turbine load was increased, the dump valves started to modulate closed and Tave was held stable at approximately 580°F.

The operator at this time felt the transient was under control, and since Tave was stable he reset the Steam Dump System load rejection signal, not realizing that it would cause the steam dump valves to close.

Just prior to the disarming of the Steam Dump System and the closure of the dump valves, reactor power was 92% and turbine load was 500 MWe. Turbine load was still being increased in an attempt to reduce the mismatch between turbine load and reactor power, and the steam dump was maintaining Tave approximately 580°F. When the steam dump was disarmed and the valves closed, the ability to reject heat via the steam dump was lost. This resulted in a rapid increase in Tave, since reactor power was significantly higher than turbine power. The rapid increase in RCS Tave to 592°F caused pressurizer level to rapidly increase from 54% to 78% due to the specific volume change. Pressure correspondingly increased from 2200 psig to a peak of 2325 psig due to the level increase and the compression of the steam bubble. The pressure increase was offset by the operation of both pressurizer spray valves.

The rapid increase in RCS Tave was also reflected back into the secondary side of the unit. It caused steam generator pressure to rapidly increase which caused Nos. 22 and 24 MSIV's to start to close. The partial closure of the Main Steam Isolation Valves (MSIV's) was due to the increased differential pressure across the steam closing pistons in the valve operators. The operator noted the loss of the open lights on the MSIV's and initiated a re-open signal to the No. 22 and 24 MSIV's and the valves returned to their full open position.

At 0117 hours, RCS Tave reached its maximum value of 592°F.

Due to the rapid increase in steam pressure, the operating shift was anticipating lifting of the steam generator safety valves. When steam pressure increased to 1080 psig. the No. 23 Steam Generator Safety, 23MS15, lifted. Shift personnel were anticipating this and were aware that a safety had lifted since they had previously experienced the noise level. In order to determine which safety had lifted, an equipment operator was immediately dispatched to observe which safety was discharging.

At 0123 hours, the combined effects of RCS boration and increasing turbine load started to reduce Tave. Pressurizer level and pressure also started to decrease. Pressure was decreasing under the influence of pressurizer spray with both spray valves fully open. The decrease in pressurizer level was due to the specific volume change in the RCS. Manual boration of the RCS was also stopped at this time since it was beginning to take effect.

At 0135 hours, pressurizer pressure was at 2160 psig, and the operator noticed that he had a closed indication on only one spray valve even though the controller demand signal was at zero. When he went to manual on the spray valve controller and touched the close pushbutton, the closed light illuminated immediately. This indicated that valve was almost fully closed and would have closed if it had been left in automatic control.

At 0145 hours, pressurizer pressure and level stopped decreasing. Level was at 22% and pressure was 2050 psig. The large drop in pressure corresponded to the decrease in pressurizer level. All pressurizer heaters energized and pressure began increasing. RCS Tave continued to decrease as boron mixing continued.

At 0148 hours, pressurizer pressure was at 2140 psig and increasing. Level was at 50%, and RCS Tave was still decreasing. As Tave decreased, turbine load was also decreased to prevent reducing RCS Tave too low.

At 0150 hours, pressurizer pressure was at 2260 psig. The pressure controls were returned to automatic to control the pressure swings as Tave decreased, and turbine load was decreased to follow the programmed Tave values.

At 0210 hours, the unit was in a stable condition; pressurizer pressure 2235 psig, pressurizer level at 32%, Tave at 558°F, reactor power 46%, and turbine load at 480 MWe gross. The No. 23 steam generator safety valve 23MS15, however, had failed to fully reseat and was still discharging steam; but had no effect on the unit stability. The decision was made to hold the unit at power because if the unit was shutdown with the partially stuck-open safety, it would go into an uncontrolled cooldown transient, which would have been undesirable.

It was attempted to fully reseat 23MS15 by lowering RCS Tave 4-6°F below Tref and then by manually cycling open 23MS10, the No. 23 steam generator atmospheric relief valve. Steam Generator pressure decreased to 800 psig, but 23MS15 still failed to fully reseat. The attempt was made 3 times. It was decided to attempt to manually reseat the partially open safety valve.

Upon investigation it was discovered that the lifting disc associated with the manual lifting arm had rotated approximately 2 full turns down the valve stem and was jamming valve travel. The manual lifting device was removed and the valve closed fully.

ANALYSIS OF OCCURRENCE:

The limits on the DNB related parameters assure that each of the parameters are maintained within the normal steady state envelope of operation assumed in the transient and accident analyses. The limits are consistent with the initial FSAR assumptions and have been analytically demonstrated adequate to maintain a minimum DNBR of 1.30 throughout each analyzed transient.

ANALYSIS OF OCCURRENCE: (continued)

It was concluded that at no time was the safety of the unit in jeopardy since during the entire transient, all unit parameters remained within the protection envelope provided by the Reactor Protection System, and no Limiting Safety System settings were reached. The decision to hold the plant at power with the partially open Steam Generator Safety Valve was valid since this action avoided an uncontrolled transient which would have resulted in challenging the Emergency Safeguards System.

Action Statement 3.2.5 was entered at 0110 hours and terminated at 0210 hours.

Action Statement 3.2.5 requires:

> With any of the DNB parameters exceeding the associated limit, restore the parameter to within its limit within 2 hours or reduce thermal power to less than 5% of rated thermal power within the next 4 hours.

An evaluation was conducted by the Power Systems Group of the Engineering and Construction Department to determine the cause for the loss of Steam Generator Feed Pump suction pressure on Unit 2. It was determined that when turbine load is rapidly decreased, two things occur. First, Steam Generator (SG) level shrinks. To compensate for the level decrease, feed flow momentarily increases. This results in increased flow from the Consensate Pumps and Heater Drain Pumps. The second thing which occurs is a decrease in turbine extraction steam pressure. This causes a decrease in pressure in the shell side of the fifth and sixth point heaters which consequently reduces the pressure in the Heater Drain Tanks. This reduced pressure results in flashing of the water in the tanks. This flashing reduces the Heater Drain Tank levels, and when combined with the increased flow, causes the level in the tanks to decrease to the point where the pump discharge valves begin throttling closed to maintain level. The reduction in Heater Drain Pump flow causes a further reduction in Feed Pump suction pressure since the Condensate Pumps are not capable of providing the required flow. Therefore, a further reduction in load is required and the cycle continues to repeat itself until the Feed Pumps finally trip.

CORRECTIVE ACTION:

As a result of this occurrence, Station Operating Procedures have been revised to provide more guidance to the operating shift and additional operator training has been implemented. As noted, an Engineering Evaluation was performed. Based on that evaluation, a Design Change Request, 2EC-1380, was submitted to replace the Condensate Pumps with higher head pumps and install a heater drain tank quench system. A Supplemental Report will be submitted upon completion.

FAILURE DATA:

Not Applicable

Prepared By R. Heller

General Manager -
Salem Operations

SORC Meeting No. 82-78