PP&L Pennsylvania Power & Light Company

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Bruce D. Kenyon
Vice President-Nuclear Operations
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JUN 0 8 1984

Dr. Thomas E. Murley
Regional Administrator, Region 1
U.S. Nuclear Regulatory Commission
631 Park Avenue
King of Prussia, PA 19406

SUSQUEHANNA STEAM ELECTRIC STATION
TURBINE BYPASS TRANSIENT
ER 100508 FILE 841
PLA-2229

Docket No. 50-388

Dear Dr. Murley:

As a followup to our meeting with your staff on May 31, 1984, attached is a detailed description and evaluation of the turbine bypass transient which occurred at Susquehanna SES Unit 2 on May 28, 1984. Also attached is the NSAG report on the transient.

Very truly yours,

B D Kenyon

B. D. Kenyon
Vice President-Nuclear Operations

Attachment

cc: R. W. Starostecki - NRC Region 1
R. H. Jacobs - NRC Resident Inspector
R. L. Perch - NRC Bethesda

IE22

1/1

Attachment 1
PLA-2229

Turbine Bypass Transient

Following shift turnover on May 27, 1984, Operations personnel began establishing plant conditions to perform the RCIC controller hot functional tune-up test (HF-250-010). The EHC pressure setpoint was reduced from an initial value of approximately 950 PSIG to 920 PSIG at the completion of CRD scram time testing at 00:10 on May 28, 1984. Control rods were then withdrawn to increase reactor power to open the #1 turbine bypass valve to approximately 50% to ensure adequate pressure control during the RCIC hot functional test.

Steam dilution flow to the secondary Steam Jet Air Ejector (SJAE) began to oscillate (+/-150 lb/hr) at approximately 23:50 based on strip chart recorder data. This corresponds to the decrease of the EHC pressure setpoint. At approximately 00:45 the SJAE steam flow increased from 9400 lb/hr to 9650 lb/hr as reactor pressure increased. The flow then decreased to 9400 lb/hr as reactor pressure decreased.

At approximately 01:00 a control rod was selected and withdrawn. This action directly preceded an increasing amplitude oscillation of turbine bypass valve position as the #1 bypass valve re-positioned to maintain pressure setpoint. The oscillation induced reactor pressure and bypass steam flow perturbations which apparently induced offgas system steam dilution flow oscillations. Variations in the offgas system flow rate would have a negligible effect on reactor pressure and would not be expected to influence EHC operation. The offgas system oscillations were further complicated by the fact that two root valves to the offgas main steam pressure reducing controller (PC-20701A) were isolated causing the pressure control valves to be open fully. A review of previous oscillations in the SJAE steam flow showed two oscillations occurred on May 27, 1984 when reactor pressure was adjusted. Had the pressure regulating valves been operable, the oscillations would have been dampened. Offgas isolated on low steam dilution flow at approximately 01:01:03 due to the oscillations in the steam flow caused by the increasing magnitude of the oscillations in the total bypass valve capacity. This generated the first indication to the plant control operator (PCO) that an abnormal plant condition existed. Subsequent engineering simulations of the resulting transient support the supposition that the #2 turbine bypass valve opened at 01:01:15 which pressurized the #2 bypass valve discharge piping and caused narrow range reactor pressure to drop to 896 PSIG. Data in the attached Figure 1 shows an expected reactor pressure drop of 20 pounds based on main steam line surge flow when two bypass valves initially open. This correlates well with the recorded pressure decrease of 19 pounds and recorded steam flow increase. As reactor pressure decreased, vessel level swelled to approximately +53" due to increased void formation and a HPCI high level trip signal was generated. Process computer data indicates the bypass valves went fully closed to recover reactor pressure. Vessel level dropped to 30" and the feedwater system, in automatic vessel level control using the low load controller (LIC-2R602), responded to the level perturbation by increasing feedwater flow. The effect of reactor pressure increasing due to the bypass valve closure provided a net reactivity increase and subsequent small power spike.

The maximum APRM power level recorded in the Shift Supervisor and Startup Test logs during the transient was 10% on APRM 'E'. This APRM had a gain adjustment factor of 1.85 as determined by Startup Test (ST) 12.1 which would indicate an actual power level of 5.4% rated power. This is supported by the fact that a rod block was received, however no reactor scram signals were generated. Based on APRM settings for a rod block at 11% indicated power and scram function at 14% indicated power, and applying the current gain adjustment factors for individual APRM's, the minimum power at which a rod block would occur was 4.6% actual power. The minimum power at which a half scram would occur was 5.9% actual power. This would indicate that the actual power level reached during the transient is bounded by 4.6% to 5.9% rated power. A separate transient power analysis using the actual IRM recorder traces, as adjusted by a Hot Functional test which correlated observed IRM readings to the calibrated APRM readings, indicates the initial power level was 3.2% and that actual power reached during the transient was between 4.7% and 5.0% rated power.

Reactor pressure continued to increase to a maximum value of 925 PSIG at 01:01:48 at which point turbine bypass valves #1 and #2 re-opened to 34% of total bypass valve capacity. Reactor pressure decreased to 911 PSIG and both bypass valves reclosed at 01:01:53 to regulate pressure based on the pressure setpoint. The #1 bypass valve re-opened at 01:02:03 and oscillated three times while attempting to stabilize reactor pressure. When pressure again exceeded the pressure setpoint at 01:02:58 the #2 bypass valve re-opened and a maximum of 28% total bypass valve capacity was recorded by the process computer. Maximum reactor pressure reached prior to the second bypass valve operation was 924 PSIG. Figure 2 graphically depicts the total bypass valve open position and narrow range reactor pressure response during the transient. At 01:03:09 the #2 bypass valve reclosed and the #1 bypass valve stabilized reactor pressure at approximately 918 PSIG. Minor reactor vessel level swings and a power transient, less severe than the initial power spike, also occurred during these subsequent bypass valve operations.

To mitigate the transient, Operations personnel began to insert control rods and placed the feedwater low load controller in manual to minimize further vessel level oscillations. Plant conditions stabilized at approximately 01:04 and the offgas system hydrogen recombiner was returned to service. Shift supervision, believing the offgas system had initiated the transient, then directed the PCO to manually isolate the offgas system to preclude further transient operation. At 01:05:19 the main steam supply (HV-20701A/B) to offgas was isolated. At 01:15 the Unit #2 recombiner was shutdown and the mechanical vacuum pump was placed in service. HF-250-010 and ST 14.2 (RCIC Quick Start to the Vessel) were satisfactorily completed at 04:58.

Subsequent plant staff I&C and General Electric investigation of the EHC pressure control and bypass valve control logic indicated that all control functions were operating normally. Plant staff Mechanical Maintenance investigation of the #1 bypass valve revealed that a chipping hammer was found wedged between the bypass valve seat and the valve disc preventing the #1 bypass valve from fully closing. Since the valve indicated fully closed on two occasions during the transient, it can be reasonably assumed that the hammer became lodged in the valve either during the final stages of the transient or when plant conditions had stabilized following the transient. The presence of the hammer in the vicinity of the #1 bypass valve may have impeded the steam flow rate through the valve, possibly producing the pressure increase which precipitated the initial observed bypass valve oscillation. The chipping hammer that was retrieved was the type typically used during welding procedures. The head of the hammer was 6" wide and tapered to a point with a chisel design at the opposite end. Apparently the bypass valve, upon closing, severed the spring portion from the handle and the spring was lost in the main condenser. Approximately 6" of the handle remained intact. The upper portion of the handle was flattened on both sides due to operation of the bypass valve. Mechanical interference of the bypass valve operation caused by either the hammer or the spring device attached to the handle can only be inferred but not conclusively demonstrated. Disassembly of the #1 bypass valve showed small dents on the disc and the seat of the valve. All the dents on the disc appeared to be concentrated in an area approximately 1 square inch. The dents on the seat corresponded to the same relative position as on the disc. The seat was machined to remove the dents and the disc was replaced due to the difficulties in removing the old disc.

An evaluation of the event by PP&L's Engineering Analysis Group has determined that the event is less limiting than the main turbine trip without bypass transient from <30% power which is discussed in Section 15.2.3 of the FSAR. The turbine trip event results in a greater reduction in steam flow and is initiated from a higher power level. The higher initial power level results in a larger void collapse in the core causing a higher power spike. Section 15.2.3.3.3.3 of the FSAR states that the turbine trip without bypass event results in a high vessel pressure scram. Therefore, the peak power remains below the flow biased simulated thermal power upscale trip setpoint and the MCPR remains well above the GETAB safety limit. Since the initial power was lower, the steam flow reduction and subsequent pressurization was less. The pressurization increase was mitigated by bypass valve operation, and therefore the event that occurred on May 28, 1984 was less severe than a turbine trip without bypass event from low power.

Figure 1

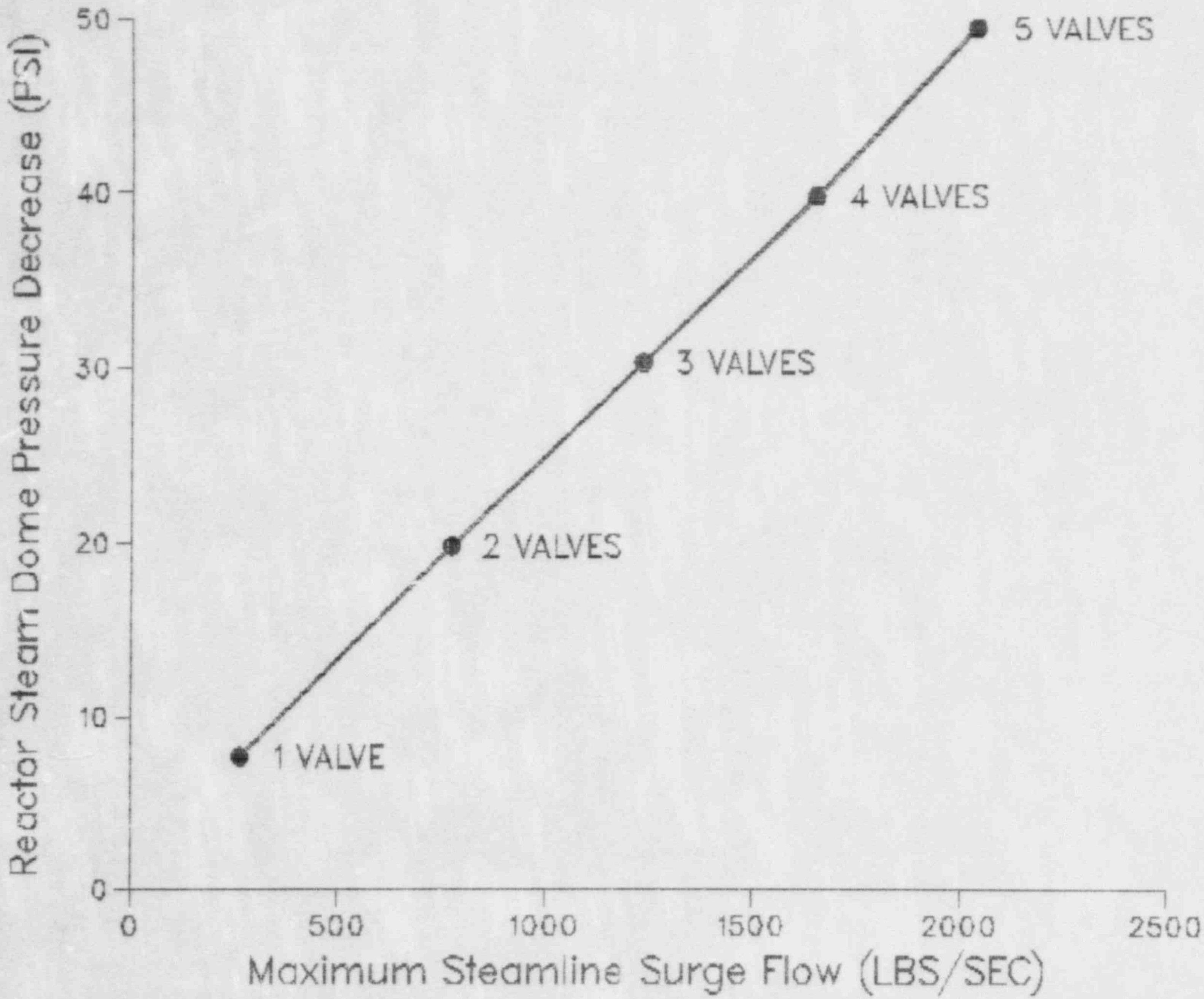
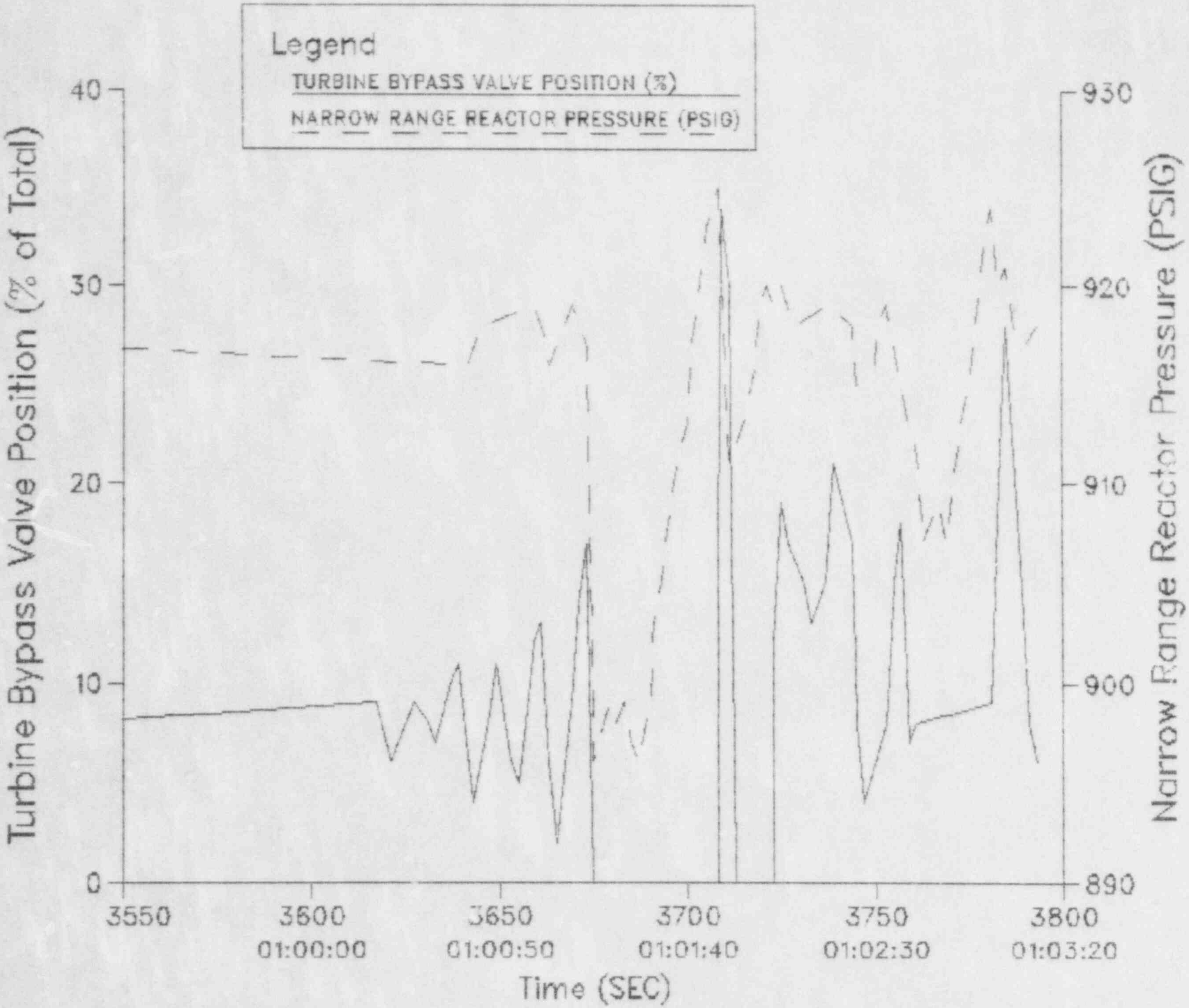

Reactor Steam Dome Pressure Decrease (PSI)
0
10
20
30
40
50
1 VALVE
2 VALVES
3 VALVES
4 VALVES
5 VALVES
0
500
1000
1500
2000
2500
Maximum Steamline Surge Flow (LBS/SEC)

Figure 2


Legend
TURBINE BYPASS VALVE POSITION (%)
NARROW RANGE REACTOR PRESSURE (PSIG)
Turbine Bypass Valve Position (% of Total)
Narrow Range Reactor Pressure (PSIG)
40
30
20
10
0
930
920
910
900
890
3550
3600
01:00:00
3650
01:00:50
3700
01:01:40
3750
01:02:30
3800
01:03:20
Time (SEC)

Nuclear Safety Assessment

Group Project Report No. 7-84

Investigation of Unit Two

Power Transient of May 28, 1984

Report Date - 6/6/84

J. R. Miltenberger
Manager-Nuclear Safety Assessment Group

FILE 917-1

1.0 Summary

At about 0100 on 5/28/84 Unit Two reactor power increased to a level of about 5.9%. This exceeded the license limit of 5.0%. The power excursion lasted for less than three minutes. It was apparently caused by a malfunction of the Number One Turbine Bypass Valve. The transient occurred while the operators were establishing plant conditions for an approved test. Operator actions were prompt and effective. The reactor did not SCRAM. No emergency core cooling systems were actuated. No nuclear safety hazard existed.

2.0 Description of Incident

At the time of the incident power was being increased by withdrawing control rods. The objective was to achieve about 60% opening of the No. 1 Turbine Bypass Valve (TBV), which occurs at a power level of about 4%. This action would provide sufficient steam flow to permit testing of the RCIC system without perturbating plant pressure.

At a reactor power of about 3.8% a Low Dilution Flow alarm was received for the Off Gas Recombiner System. The operators observed that reactor power was increasing and reactor water level was fluctuating. They inserted control rods, took manual control of the feed water system, and then took the Unit Two Off Gas Recombiner System out of service. These actions terminated the transient. Power rose to a level of 5.9% on the highest indication (APRM B) and then returned to less than 4%.

The Duty Manager was informed. At 0159 the NRC was informed that a power excursion beyond the license limit had occurred.

After the transient had settled out the Duty Manager made the decision to continue testing. The RCIC tests were completed as scheduled. At 0530 a normal shutdown began. At 0600 it was discovered that No. 1 TBV would not close. It hung up at about 18% open. The Duty Manager was informed and trouble shooting of the TBV was commenced. The reactor was shutdown at 1350.

3.0 Discussion

The incident occurred during the course of establishing plant conditions for planned tests of the RCIC system. Power was well within the specified limits when the transient began. The transient was caused by equipment malfunction. Since Plant Staff was investigating the technical aspects of the transient in detail, the Nuclear Safety Assessment Group concentrated upon the programmatic issues. NSAG attempted to determine whether the plant was being operated prudently.

3.1 Power Monitoring was Correct

Power was being monitored using the six Average Power Range Monitors (APRM's), which were displayed on a CRT on panel 2C651. The gains of the APRM's had been adjusted to the highest possible values in order to lower the actual SCRAM set points for initial testing and to improve the indication at the low end of the scale. Gain settings ranged from 1.85 to 2.37. The APRM displays showed the actual power multiplied by the gain setting. The maximum reading observed during the transient was 11% read on APRM "B". The actual power, then, was 11% divided by the gain of 1.85 or 5.9%.

The Technical Specifications require that during startup the APRM SCRAM be set at a maximum of 15% and the rod block be set at a maximum of 12% (Tables 2.2.1-1 and 3.3.6-2). The values actually set were: SCRAM at 14% and rod block at 11%. When one corrects for instrument gain, the SCRAM values would range between 7.57% and 5.91% and the rod blocks between 5.95% and 4.64%.

During the transient a rod block occurred but no SCRAM signals came in. This fixes the actual power between 4.64% and 5.91% (minimum rod block setting and minimum SCRAM setting).

The Intermediate Range Monitors (IRM's) were displayed on recorders on the Standby Information Panel. It is impossible to fix an accurate correlation between the IRM readings and core thermal power.

The APRM's were calibrated on 1/15/84. The IRM's were calibrated on 4/27/84 (Both are semi-annual requirements, Tech Specs Table 4.3.1.1-1). The Weekly Channel Functional Tests were done on 5/21/84 (APRM) and on 5/22/84 (IRM). The next tests were done 5/29/84 and 5/30/84 respectively. There is every reason to believe that the APRM and the IRM SCRAMs would have functioned if required.

The operators had been specifically directed to monitor power on the APRM's. A night order entry dated 5/21/84 reads,

> "Unit 2 APRM's used to determine 5% power limit. (Rated Temp and Press 75% 1 bypass.)"

The order is somewhat vague in that it does not specify that the power limit is actual power not indicated power. That is, it does not clearly state that the limit is the APRM reading divided by the instrument gain. However, this was understood. The instrument gains were posted on panel 2C651. The operator, and the startup engineer referenced the gain settings in their log entries. There was no confusion on the part of the operating crew. Monitoring power was not an issue in the incident.

At the time of the incident reactor power was being increased in preparation for testing the RCIC system. The test procedures called for power level greater than 2% with sufficient steam flow to prevent reactor pressure decay during RCIC operation. The Unit Supervisor's goal was 60% opening on No. 1 TBV which corresponds to about 4% actual power. (APRM reading corrected for gain.) When the transient occurred APRM "B" reading was about 7% and No. 1 TBV was about 55% open. A 7% reading equates to 3.8% actual power. The plant was being operated conservatively. Three-point-eight percent is comfortably below the limit of 5%.

In summary:

- o The instruments were set in a conservative manner.
- o The instruments were in calibration and the required functional tests had been done.
- o SCRAM protection existed from the APRM's and the IRM's.
- o The operators were monitoring power in accordance with management's instructions.
- o The plant was operating at a conservative power level.

3.2 The Bypass System had been Properly Tested

The following tests were performed prior to the incident. They required proper response by the pressure regulator:

Pressure	Test	Description
135#	HF-293-030	Verify proper response of BPV's to pressure regulator setpoint changes.
150#	SO-250-003	RCIC Full Flow Test Steam flow to RCIC requires Pressure Regulator (P.R.) to close BPV slightly to maintain pressure. Initially No. 1 BPV about 0.5 open.
150#	SO-252-003	HPCI Full Flow Test Steam flow to HPCI requires P.R. to close BPV by ~50% to maintain pressure. Initially, #1 BPV-3/4 open.
150#	ST26.1	SRV Low Pressure Test Steam flow to S/RV requires P.R. to close ~1 BPV to maintain pressure. Initially, ~2 BPV's open.
920#	HF-250-010 ST14.1 SO-250-002	RCIC Functional Checks RCIC CST to CST RCIC Full Flow Test Steam Flow to RCIC requires P.R. to close ~5% of one BPV to maintain pressure.

920#	SO-252-002	HPCI Full Flow Test Steam flow to HPCI requires P.R. to close ~50% of one BPV to maintain pressure.
128-250# 920-950#	CRD Movement	Movement of CRD's to increase power to perform above test requires P.R. to open BPV's to maintain pressure.

In each of the above tests the performance of the system was monitored using the GETARS. The turbine bypass valves responded properly in every one of these tests.

On the night of 5/28/84 there was no reason to expect problems with the pressure control system or the bypass valves.

3.3 Incident Caused by Equipment Malfunction

At about 0100:30 the TBV's began to oscillate. At 0101 a Low Dilution Flow alarm was received on the Off Gas Recombiner Panel. The maximum power occurred at about 0101:45, and the transient was over by 0104.

Over the course of the previous twenty-four hours several flow oscillations had occurred in the Off Gas Recombiner System. It appeared at the time that the oscillations in the TBV's had been caused by the perturbation on the Off Gas System. The Off Gas System was taken out of service and vacuum was maintained by the mechanical vacuum pump. No further oscillations were observed.

However, during the subsequent reactor shut down TBV No. 1 could not be closed fully. Subsequent trouble shooting indicated that at least one TBV was operating sluggishly. Debris was found in the number one bypass valve.

NSAG did not attempt to determine the cause of the equipment malfunction. That is being done by the plant staff Technical Section. We are satisfied, however, that the transient was not caused by operator error. Clearly there was a malfunction of some kind which caused reactor pressure and feed water flow transients that resulted in minor power excursions.

3.4 Operator Response was Prompt and Effective

The first indication of a problem was the Low Dilution Flow alarm which occurred at 0101. At this time APRM "B" indicated that reactor power was about 7% (3.8% corrected for gain). NSAG could not determine precisely whether or not a control rod was being moved at the time the alarm appeared. At any rate, the operators observed that power was increasing, that the TBV's were oscillating and that reactor water level was fluctuating. The operators inserted control rods into the core and took manual control of feed water flow. Power increased to 11% on APRM B. Power turned at about 0101:45 and the TBV oscillation died out by 0104. The operators then isolated the Off Gas Recombiner System and started the mechanical vacuum pump.

Within a period of less than four minutes the transient was over. The operators then proceeded to correct the apparent cause of the problem by securing steam to the air ejector system. There were no further symptoms until about 0600 when TBV No. 1 would not close during the plant shut down.

The operators recognized that a limit may have been exceeded. After conditions had stabilized they notified the Duty Manager and subsequently notified the NRC.

In the opinion of NSAG, the operators responded effectively. They recognized the problem, took steps to terminate the transient, corrected what they believed to be the cause, and informed the proper authorities.

3.5 Evolutions were Authorized

Tests HF-250-010, RCIC Turbine Control System Tune Up and ST14.2, Reactor Vessel Injection were scheduled on the Startup and Test Three-Day Schedule dated 5/25/84 and signed by the Day Shift Supervisor. The cover sheet indicating that the schedule applied from 1600 5/25/84 through 1600 5/29/84 was signed by the Unit Coordinator. The test procedures had been approved by the PORC and had been signed by the Plant Superintendent. The initial conditions were in accordance with the procedures and had been successfully achieved on several previous occasions. After conditions had stabilized the Duty Manager was informed. He concurred in the decision to notify the NRC and he granted permission to complete the scheduled testing.

The evolutions were properly authorized by cognizant line management. There was no improvisation by the operating crew.

3.6 One Hour Report was Required

There has been some discussion as to whether the event should have been reported to the NRC at all. The reactor was being operated within the limits of the license and a brief transient was caused by an equipment malfunction. No safety limits were violated. In the opinion of NSAG, the situation is analogous to operating at 100% power and experiencing a casualty which causes an excursion above the steady state limit but below the SCRAM setting.

The 100% power level excursion is covered by NRC memorandum SSINS 0200 E. L. Jordan to Distribution, "Discussion of Licensing Power Level (AITS F14580H2)", August 22, 1980. The basic guidance is that average power over an 8 hour interval may not exceed the license limit and that the instantaneous power may not exceed 102% of the license limit.

102% of 5% is 5.1%. An excursion of 5.9% violates the 102% guideline for instantaneous power.

Paragraph 6.6 of the Technical Specifications defines Reportable Event Action. It states,

> "a) The commission shall be notified and a report submitted pursuant to the requirements of Section 50.73 to 10CFR50,..."

Specific instructions to the operators are found in Administrative Procedure AD-QA-424, Significant Operating Occurrence Reports, Rev. 4 effective 1/1/84. Table A of Attachment C Operational Events One Hour ENS Notification lists, item 8, "Violations of Operating License." Page 27 of 53 discusses item 8 and specifically states "Any violation of License Conditions 2C(1)...". Condition 2C(1) of the Unit Two operating license states "...Pending Commission approval, this license is restricted to power limits not to exceed five percent of full power (164.6 megawatts thermal)."

It is clear that the decision to make a one-hour report to the NRC was consistent with the Technical Specifications, the NRC interpretation of the power limits, and the station instructions.

3.7 No Hazard Existed

The Nuclear Plant Engineering Engineering Analysis Group analyzed the transient and determined that it is within the bounds of transients analyzed in the FSAR.

A copy of the NPE Evaluation (File 247-01 of 5/30/84) is attached.

4.0 Conclusions

1. The license power limit of 5% was exceeded for less than 3 minutes. Maximum power was 5.9% per APRM "B" after gain adjustment.
2. No nuclear safety hazard existed to the plant or to the public.
3. The transient was caused by an equipment malfunction.
4. Operator actions to control the casualty were prompt and effective.
5. All evolutions were authorized by responsible line management.

jrm/rpe143i/rla

PP&L

MEMORANDUM

TO: Rick Nobles

DATE: May 30, 1984

FROM: A. J. Roscioli

JOB: ER 100450

NUMBER: EA-096

COPIES TO: T. M. Crimmins, A6-2
G. D. Miller, A2-5
J. S. Stefanko, A2-5
SRMS Corres. File, A6-2
SRMS Letter File, A6-2

FILE: 247-01

REPLY: NO

SUBJECT: EVALUATION OF MAY 28, 1984 SSES UNIT 2 TRANSIENT EVENT

During the 5/28/84 SSES plant event, the bypass valves closed as demanded by the pressure regulation controller. The bypass valves remained closed until pressure and power exceeded their initial values of the transient. As a result power increased above the 5% licensed power level before the bypass valves reopened to control pressure and mitigate the power rise.

This event is less limiting than the Turbine Trip without Bypass transient from ≤ 30% power which is discussed in Section 15.2.3 of the SSES FSAR. The turbine trip event results in a faster reduction in steam flow and a higher initial power level. The higher initial power level results in a larger void collapse in the core causing a higher power spike. Section 15.2.3.3.3.3 states that the turbine trip without bypass event results in a high vessel pressure scram. Therefore, the peak power remains below the flow biased simulated thermal power upscale trip setpoint and the MCPR remains well above the GETAB safety limit.

Since the initial power is lower, the steam flow reduction and subsequent pressurization is slower, the magnitude of the pressurization is mitigated by reopening of the bypass valves, and the void collapse is less severe due to the lower initial power, the event that occurred at SSES on 5/28/84 is much less severe than the Turbine Trip without bypass event from low power which is analyzed in Section 15.2.3 of the FSAR.

A. J. Rosciol
A. J. Roscioli

AJR/er

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