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Mr. James G. Keppler
Regional Director, Region III
Office of Inspection and Enforcement
U. S. Nuclear Regulatory Commission
799 Roosevelt Road
Glen Ellyn, Illinois 60137

Dear Mr. Keppler:

Supplement to Reportable Occurrence NP-32-77-16
Davis-Besse Nuclear Power Station Unit 1
Date of Occurrence: September 24, 1977

Enclosed find three copies of Licensee Event Report NP-32-77-16 Supplement, whi
is being submitted in accordance with Technical Specification 6.9 to provide ad
tional information of the subject occurrence.

Please note this report also satisfies the special 90 day report requirement of
Technical Specification 6.9.2 for the Emergency Core Cooling Actuation on Septem
ber 24, 1977.

Yours truly,

Terry D. Murray

Terry D. Murray
Station Superintendent
Davis-Besse Nuclear Power Station

TDM/JRL/ljk

Enclosures

cc: Dr. Ernst Volgenau, Director
Office of Inspection and Enforcement
Encl: 40 copies Supplement

Mr. William G. McDonald, Director
Office of Management
Information and Program Control
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Edison Electric Institute
Company Nuclear Review Board M

1. SUMMARY

On September 24, 1977, a series of events occurred at the Davis-Besse Unit 1 which resulted in depressurization of the primary system from a normal operating pressure of 2150 psi to 900 psi in approximately 5 minutes, and the release of approximately 11,000 gallons of water in the form of steam within the containment through the pressurizer quench tank rupture disc.

On the afternoon of Saturday, September 24, 1977, the main turbine was shut down to repair a leak in a pressure sensing connection on a steam line from the turbine governing valves to the turbine inlet. The reactor was being held critical at approximately 9% thermal power.

At 2134 hours, a spurious half trip occurred in the Steam Feedwater Rupture Control System (SFRCS). This caused the startup feedwater valve on the No. 2 steam generator (which is the normal feed path at this power level) to close. Closure of this valve resulted in a low No. 2 steam generator level, which then resulted in a normal full trip of the SFRCS for this condition and initiation of the SFRCS. SFRCS initiation closes both main steam isolation valves and initiates feedwater flow to both steam generators from their individual steam-driven auxiliary feedpumps.

The half trip and resulting full trip of the SFRCS caused a reduction in heat removal from the primary system and a corresponding temperature/pressure rise in the primary system. The pressure rise in the primary system caused the pressurizer power relief valve to lift. This valve then rapidly oscillated closed-to-open approximately nine times and remained in the full open position.

The temperature rise in the primary system caused an increase in the pressurizer level, and the operator manually tripped the reactor on high pressurizer level approximately two minutes after the half trip on the SFRCS occurred.

The pressurizer power relief valve, in the full open position, rapidly reduced the primary system pressure, and a Safety Features Actuation System (SFAS) trip occurred at the 1600 psi setpoint of the primary system. The power relief valve discharge goes to the pressurizer quench tank, which became overloaded and overpressurized, and approximately 4½ minutes after reactor trip the rupture disc in this tank relieved due to overpressure, venting the steam into the containment. Approximately 20 minutes after reactor trip, the operators diagnosed the reason for the primary system depressurization as being the power relief valve, and from the control room closed the motorized block valve ahead of the power relief valve, terminating the loss of primary coolant into the containment.

Subsequent operator action using makeup pumps and high pressure injection pumps stabilized the primary system pressure and pressurizer level and a controlled shutdown to cold shutdown conditions followed.

The major physical damage from the incident was to the refle insulation on the lower part of the No. 2 steam generator, w ceived the jet of steam coming from the pressurizer quench t ventilating duct in the area of the quench tank was dimpled straightening. Twenty-three panels of reflective metal insul required replacement. Entry into the containment was made at September 25, 1977, for cleanup operations.

Another event occurred in the course of this incident that di contribute materially to the above events, but did result in steam generator going dry. This was the failure of the No. 2 feedpump to come up to full speed following the SFRCS trip. feedpump came up to approximately 2600 rpm and stayed at this with no flow to the steam generator until approximately 12 mi after reactor trip, when the operators placed its control in brought it up to full speed (commencing feedwater flow to the generator).

The depressurization of the primary system resulted in steam f in the primary system, but evaluation has shown there was no a boiling in the core. The pressure/temperature transients in t system components including the steam generator, reactor coola and fuel were severe, but analysis and subsequent pump testing shown that these transients are within the design allowables a no detrimental effects are to be expected on the primary syste or fuel.

System/component maloperation or failure occurred in three are (half-trip initiation), pressurizer power relief valve (oscill failing in the open position) and auxiliary feedpump (failure up to full speed). The causes of these maloperation/failures h investigated and corrective action taken to prevent recurrence. Additional system/equipment modifications have been completed o initiated, and additional training has been initiated to streng the systems intelligence available to the operators and facilit operator action.

At no time during the sequence of events was there any jeopardy health and safety of the public or plant operators, and there w release of radioactivity to the environment. Activity levels w the containment at no time impeded containment access.

All safety systems performed their design functions in the prop manner. Operator action was timely and proper throughout the s of events.

2. EVENT DESCRIPTION

At the time this incident occurred, the reactimeter data logging system was in service which recorded at high speed a number of system parameters that would not have been available on such a time base through normal station instrumentation and records. This information, together with the computer alarm logging, has permitted a very detailed plotting of the transient conditions in the primary and secondary systems keyed to the system, component and operator actions. This data is plotted on four Figures in Exhibit B. Figure 1 is an 11-minute plot of primary system parameters from one (1) minute prior to event initiation (SFRCS half trip). Figure 2 is a 130-minute plot of three primary system parameters. Figures 3 and 4 are 95-minute plots of pressure and temperature for steam generators No. 1 and No. 2 respectively.

The event started at time 21:34:20 (T = 0) on September 24, 1977. The plant was in Mode 1 with Power (MWT) = 263. The turbine had been shutdown earlier in the evening to repair a leak in the main steam line at an instrument connection between the turbine stop valves and the high pressure turbine. At this time a half trip of the Steam and Feedwater Rupture Control System (SFRCS) was initiated by an unknown cause. The trip closed the startup feedwater valve to No. 2 steam generator and stopped all feedwater to this generator (at this low power level the main feedwater block valve is closed, isolating the main feedwater control valve). The low level alarm was reached in No. 2 steam generator at T = 24 sec. Before the operator could identify and correct the problem, this low level in No. 2 steam generator correctly produced a full trip of the SFRCS. This trip closed the main steam isolation valves and feedwater isolation valves in both steam generators (T = 58 sec.). SFRCS initiation also started both auxiliary feedwater pumps. The number one pump performed as intended, however, number two auxiliary feedwater pump only came up to 2600 rpm, insufficient to feed its steam generator (No. 2).

The loss of feedwater, first to one and then both steam generators, caused an increase in reactor coolant temperature, which resulted in an increase in pressurizer level and reactor coolant system pressure. At 2255 PSIG the pressurizer electromatic relief valve received an open signal. During the next 40 seconds, it received open and close signals, cycled close-to-open nine times and then remained open. This provided a continuous vent path from the pressurizer to the quench tank. When pressurizer level rose to 290", the operator manually tripped the reactor (T = 1 min. 47 sec.). Energy escaping through the electromatic relief valve and main steam relief valves caused a rapid cooldown and depressurization of the reactor coolant system. Reactor coolant system pressure dropped to 1600 PSIG (T = 2 min. 51 sec.) initiating the Safety Features Actuation System (SFAS). This started the high pressure injection pumps and closed certain containment isolation valves.

With the electromatic relief valve still open, the quench tank rupture disc ruptured (T = 6 min.), relieving steam into the containment.

When the reactor coolant system pressure decayed to approximately 1500 psig full high pressure injection flow was established and started to raise pressurizer level. At T = 6 min. 14 sec. the operator stopped the high pressure injection pumps. (The operators had been heavily involved before this time in regaining seal injection flow to the reactor coolant pumps which had been stopped by the SFAS actuation. By T = 5 min. 20 sec. the appropriate SFAS signals had been overridden and normal flows restored to the seals of the pumps). Reactor coolant system pressure continued to decrease until saturation pressure was reached and steam began to form in the reactor coolant system (approximately T = 8 min). This caused an insurge of water into the pressurizer and the pressurizer level went off scale at 320 inches. During this level increase the operator, seeing average reactor coolant system temperature and pressurizer level increasing, stopped one reactor coolant pump in each loop (T = 9 min to reduce the heat input into the reactor coolant system.

Due to decreasing pressure in No. 2 steam generator, the SFRCS system gave a low pressure block permit signal at T = 14 min. 13 sec. This alerted the operator to the low level and feed condition of No. 2 steam generator. He blocked the low pressure trip (T = 15 min. 18 sec.), took manual control of the speed of No. 2 auxiliary feedwater pump, which commenced full feedwater flow to No. 2 steam generator (T = 16 min.). The operator saw the rapid addition of cold feedwater into No. 2 steam generator was dropping the reactor coolant system temperature and reduced the feedwater addition to this generator.

At approximately T = 21 min., it was determined that the power relief valve was remaining open and the block valve was closed, isolating the power relief valve on the pressurizer and stopping the venting of the reactor coolant system to the quench tank. At T = 31 min., pressurizer level came back on scale. At T = 41 min. the operator started a second makeup pump to try and stop the pressurizer level decrease. This additional cold water started the reactor coolant system on a slow decreasing temperature transient. At T = 43 min., pressurizer level reached the low level interlock and cut off the pressurizer heaters. At T = 49 min. the operator started a high pressure injection pump to try and stop the decreasing pressurizer level.

The level and pressure in No. 2 steam generator again decreased to the point where the SFRCS gave a low pressure block permit signal. The operator again blocked the trip and, through manual speed control of its auxiliary feedwater pump, restored level and pressure in No. 2 steam generator (T = 51 min.)

With pressurizer level well on its way to recovering, the operator stopped the high pressure injection pump (T = 53 min. 24 sec.). At T = 57 min. he restored reactor coolant makeup flow to normal. This stopped the slow decreasing reactor coolant temperature transient which started at T = 41 min. All plant parameters were now fully under control and the plant was brought to a steady state condition and a normal plant cooldown started.

3. SYSTEM-EQUIPMENT MALFUNCTION

A. General

There were three systems/components where maloperation or failure occurred during the event. These are:

1. Steam Feedwater Rupture Control System - SFRCS (half-trip initiation)

2. Power Relief Valve (oscillation and failing in the open position)

3. Auxiliary Feedpump (failure to come up to full speed)

The SFRCS is a safety system designed to provide feedwater to the steam generator/s for removal of decay heat from the primary system under a variety of hypothesized plant operating conditions. These hypothesized conditions include loss of normal feedwater flow, steam line breaks and feedwater line breaks. The components of this system include sensing systems, logic and initiating systems, main steam isolation valves, steam turbine-driven auxiliary feedwater pumps, feedwater isolation valves, auxiliary steam and feedwater supply valves and cross connect valves. A description of this system is contained in Exhibit C of this report.

A half trip of the SFRCS initiated this event by closing the startup feedwater valve to the No. 2 steam generator, which resulted in a full trip due to low steam generator level. This spurious or inadvertent half trip, and possible reasons for it occurring, are discussed in more detail below.

The pressurizer power relief valve is a 2½" pilot-actuated relief valve connected to the top of the pressurizer with a motor-operated isolation or block valve located in the line immediately ahead of the relief valve. The purpose of this power relief valve is to provide a means of relieving pressurizer pressure without requiring operation of the spring-loaded ASME Code relief valves.

During this event, the power-operated relief valve opened, oscillated closed-to-open and then failed to close and remained in the open position. Operator action from the control room closed the isolation valve ahead of the power relief valve about 20 minutes after reactor trip.

The reasons for the oscillations and the failure of the power relief valve to close are discussed in more detail below.

The steam turbine-driven auxiliary feedwater pumps are a part of the SFRCS. Upon initiation of the SFRCS, the auxiliary steam supply valve to the feedwater pump turbine opened as called for. The No. 2 auxiliary feedwater pump turbine came up to 2600 rpm and remained at this speed rather than continuing up to 3600 rpm, which is the design speed. Operator action at 14 minutes after reactor trip brought this pump up to design speed by placing the control (in the control room) in manual. Failure of this pump to come up to speed did not materially contribute to this event, but did result in the No. 2 steam generator boiling dry, which added to the transient condition in the primary system.

The reasons for this feedwater pump turbine to come up to speed are discussed in detail below.

B. <u>SFRCS</u>

The initiating event was a Steam and Feedwater Rupture Control System (SFRCS) Channel 2 momentary one-half trip from an unknown cause that went back to normal before the station computer could record the source. This one-half trip caused the following events:

1. The startup feedwater control valve (SP7A) on steam generator No. 2 closed. This caused a loss of feedwater incident on steam generator No. 2.

2. A one-half trip on Channel 2 sealed in on both main steam line isolation valves (MSIV). This one-half trip deenergized at least one solenoid valve on each MSIV, and resulted in a "Mn Stm Iso 1 (2) Trbl" alarm on the station computer for both MSIV's.

   This momentary one-half trip could have been caused by a spurious contact opening or a loose connection in a wire in a SFRCS input signal from a steam generator low pressure switch, a steam generator low level bistable or a main feedwater high pressure differential switch. The momentary one-half trip could also have been caused by trouble internal to the SFRCS cabinets. All possible causes were investigated. As a result of this investigation, it was determined that an input buffer card had failed.

4. SYSTEM TRANSIENTS AND ANALYSIS

A. Transients

During this rapid depressurization event (see section 2 abo and Exhibit 3, Figures 7-1 through 7-4), the reactor coolan pressure dropped from about 2300 psig to about 930 psig in 7¼ minutes and gradually recovered to 1800 psig in two hour (see Figure 4-1). During this 7¼ minutes the reactor coola outlet temperature dropped at varying rates from about 580 to about 533 F. Approximately 30 minutes after this initia temperature change, a second slower and smaller temperature change from 540 F to 505 F occurred over a 21-minute period. Following this second temperature decrease, the temperature gradually increased over a 2-hour period to 528 F. The reac coolant inlet temperature changes and durations were similar those of the reactor coolant outlet temperature (see Figure

The secondary side pressure in steam generator No. 1 reached maximum of 1050 psig and decreased to about 360 psig within 15 minutes (see Figure 4-3). The secondary side pressure in steam generator No. 2 reached a maximum of 930 psig, decrease to 610 psig in 14 minutes, and returned to 860 psig in 2 minu Twenty minutes later the pressure in steam generator No. 2 ag decreased to 610 psig and gradually recovered over a 2-hour period (see Figure 4-4).

B. Analysis of the Reactor Coolant System

B&W has completed its evaluation of the September 24 transien and has found no harmful short or long-term effects on the re coolant system components. For this evaluation it was conser tively assumed that the total temperature decrease occurred a the initial rate. This results in a 49° F decrease in the rea coolant outlet temperature over a 6-minute period.

The design specification for Davis-Besse Unit 1 required the evaluation of 40 cycles of a rapid depressurization event, whi included a decrease in the reactor coolant pressure from 2200 to 800 psig, a change in the reactor coolant system average temperature from 563 F to 500 F in 15 minutes, and a decrease secondary system pressure from 1030 psig to 640 psig.

The major difference between the actual transient and the desi transient is the rate of the temperature change in the reactor coolant system. The actual rate of temperature change was twic the rate of the design transient, but the total temperature cha was only 75% of that of the design transient. The net result i that the fatigue usage of this one rapid depressurization is ab the same as that predicted for one cycle of the design transien

As a more direct comparison, the transient event identified analyzed for the reactor vessel shell and compared to the de transient. The results were that the range in thermal radia gradient stress for the actual transient was 5400 psi, and t range of thermal radial gradient stress for the design trans was 6600 psi. This comparison would be representative of ot thicknesses throughout the reactor coolant system pressure boundary.

The conclusions of the analysis are:

(1) Stresses in the pressure boundary did not exceed those already calculated on a design basis. This is verified by the actual pressure not exceeding 2500 psig and the thermal transient being less severe than a combination o design transients for a rapid depressurization and a reactor trip.

(2) Fatigue life of the reactor coolant components is not affected if one cycle of the reactor trip design transie and two cycles of a rapid depressurization design transi are considered to be used for this transient. Two cycles of the rapid depressurization transient are necessary be- cause the HPI system was actuated twice during the event and two cycles are necessary to reflect the thermal trans in the high pressure injection nozzle.

The effect of the entire event on the fatigue life of the steam generators can be accounted for by using one cycle the design transient for rapid depressurization and one c of the design transient for loss of feedwater to one gene

(3) The effect of the change in water level on the pressurize has a very minor effect on the pressurizer shell stresses. The pressurizer has been previously analyzed for the therm effect of water-steam interface, and the change of level does not affect that analysis.

(4) No significant thermal shock should occur to the heaters, because the heaters were deactivated due to a low water level sensor and not reactivated until the level recovered

(5) No dynamic effects were caused by the rapid pressure decre No specific analysis was done, but a dynamic response of t shells would require a large pressure change in the order milliseconds, and the actual change was on the scale of mi

The reduced feedwater flow to steam generator No. 2 was not sufficient to maintain a water level during the first five minutes of the event and this steam generator boiled dry. The primary concern with a dry generator is the tube to shell temperature difference. In this event a water level was established before the system cooldown was started, and acceptable tube to shell temperature differences were maintained. This condition is similar to the loss of feedwater design transient, followed by restart of a dry pressurized generator using the auxiliary feedwater system.

The burst rupture disc on the pressurizer quench tank resulted in a stream of steam and water impinging on steam generator No. 2. This stream removed a section of insulation 10' high and 20' wide from the lower shell of the generator and impinged directly on the generator shell. The temperature of the impinging water was assumed to be 212° F. A conservative evaluation of the rapid temperature change in this local region of the vessel shell was performed. The results of this evaluation indicate that this one event used less than 1% of the total fatigue life of the vessel. The predicted fatigue usage factor for the 40-year design life of the vessel in this area was less than 0.10. This jet impingement did not significantly reduce the fatigue life of the steam generat

The reactor coolant pumps (RCP) experienced the following conditio during the September 24 transient.

All four RC pumps were subjected to the following:

0:00	Reactor trip
1:10	SFAS trip
1:12	Seal return valves shut for 1:16
1:13	Seal injection valves shut for 1:52 All four pumps operated for 1:15 with no seal injection and no seal return flow during the RCS de-pressurization
2:28	Seal return valves open
3:05	Seal injection valves open
6:00	Steam formation Pressure oscillating near P_{SAT} for 30 to 45 minutes
36:07	Total seal injection flow low alarm

Pump 1-1:

7:04	Pump tripped
7:43	Shaft stopped
36:07	About one minute of low seal injection flow (near 2 gpm) Flow imbalance starved seal injection
36:30	Seal return valve shut
1:12:55	Standpipe level high
1:17:07	Standpipe level normal

Pump 2-2:

4:20	High vibration
7:04	Pump tripped
36:07	Lost seal injection for about one minute
36:22	Seal return valve shut for about 40 seconds

Checkout of the reactor coolant pumps was initiated to assess whether maintenance and/or repair was required as a result of the transient.

Operational checks were required to demonstrate that no significant damage had occurred to the pump bearings, shaft and seals. The first series of tests were performed in Mode 5 due to operational restrictions. Later operational checks were performed in Mode 3. Each pump was to be operated individually for a duration not to exceed ten (10) minutes, providing all defined parameters remained within established limits.

The operational sequence was as follows:

1. Lift pumps were started and pump shafts rotated by hand. Torque values were not to exceed 200 ft-lbs. A stethoscope was provided to detect any unusual mechanical noises in seal housing area. (This was satisfactorily completed on 10/3/77).

2. Mode 5 testing at 225 psig.

   2.1 Instrumentation Required:

   a. Upper and lower cavity pressures - all four pumps.

   b. Both horizontal vibration probes - all four pumps.

   c. System pressure or suction pressure.

   d. Vertical probe on 2-2 pump.

   e. Standpipe leakage was collected and measured during the test.

   2.2 Computer Data -

   Printout NSS special summary trend for running RCP every 15 seconds.

   2.3 The following limits were not to be exceeded:

   a. Shaft vibration - 15 mils peak to peak.

b. Total standpipe leakage (upper seal leakage) plus seal return should not exceed 0.6 gpm. If, during the test this limit is exceeded, the possibility exists of an open seal. In no case will total seal leakage be allowed to exceed 1.5 gpm. If this limit is exceeded, maintenance will be required before further pump operation.

c. All other normal plant limits and precautions prevai

2.4 Sequence of Operation:

a. Secure standpipe flush.

b. Establish seal injection in accordance with plant operating procedure.

c. Measure and record standpipe leakage and return flow Confirm that total leakage limits are not exceeded.

d. Assure communication between control room and person stationed at RCP standpipe leakage drain line.

e. Countdown from 10 to 0

Start strip chart recorders at high speed;
Start Reactor Coolant Pump 2-2 in accordance with plant operating procedure.
After approximately 11 sec., reduce strip chart speed

f. Run pump for two (2) minutes unless any above limits are exceeded.

g. Data assessment by B&W and Byron-Jackson representati

h. Following assessment of data, pump may be run for an additional five (5) minutes to allow for venting procedure requirements.

i. Follow above sequence on 2-1, 1-2 and 1-1.

j. Assessment of this data will determine whether any maintenance is required before high pressure operatio is allowed.

3. Similar tests were repeated with system pressure at greater than 1300 psig before a final determination on the condition of the pumps was made.

All four reactor coolant pumps were run on 10/5/77 with the following results:

RCP 2-2 10/5/77 Run (2 min.):

Steam pressure 225 psig
2nd Seal cavity pressure 165 psig
3rd Seal cavity pressure 122.9 psig
Horizontal vibration 5 - 7.5 mils
Vertical vibration .25 mils

3rd Seal leakage plus seal return flow <

After the 2-minute run, the pump was run for 10 minutes for system venting. About 30 seconds before the pump was shutdown there was a step increase in vertical vibration to 2.5 mils. The pump was run again on 10/6/77 for 10 minutes to check out this phenomenon. The vertical vibration was again .25 mils until about 5 seconds before shutdown, when it increased to 2.5 mils. To allow a longer run time, 2-1 and 2-2 pumps were run together for 10 minutes, then 2-2 was run alone for 10 minutes. The vertical vibration stayed at .25 mils for the entire run. This was monitored during pump runs during plant heat up. It should be noted that the step increase in vertical vibration was later assessed to be spurious instrument noise as a result of a loose connector on an instrument line. After the connector was tightened, vertical vibration remained less than .25 mils peak-to-peak amplitude.

RCP 2-1

Steam pressure 225 psig
2nd Seal cavity pressure 132 psig
3rd Seal cavity pressure 70 psig
Horizontal vibration 5 - 7.5 mils

3rd Seal leakage plus return flow <

RCP 1-2

System pressure 225 psig
2nd Seal cavity pressure 40.29 psig
3rd Seal cavity pressure 81.3 psig
Horizontal vibration 5 - 7.5 mils

3rd Seal leakage plus return flow <

RCP 1-1

System pressure 225 psig
2nd Seal cavity pressure 77.98 psig
3rd Seal cavity pressure 89.27 psig
Horizontal vibration 5 - 7.5 mils

3rd Seal leakage plus return flow <

The apparent discrepancy on seal cavity pressures on 1-1 and 1-2 was checked on 10/6/77 by installing pressure gauges at the pressure transmitters. The gauges read as follows:

1-1:

2nd Seal Cavity Pressure	- 184 psig
3rd Seal Cavity Pressure	- 111 psig

1-2:

2nd Seal Cavity Pressure	- 184 psig
3rd Seal Cavity Pressure	- 112 psig

The readings indicate the seals are staging properly.

Based on the above performance, B&W saw no concern which would justify maintenance at the time.

By 10/13/77 all four reactor coolant pumps had been run at a system pressure greater than 1300 psig.

RC Pumps 2-1 and 2-2 have continued to run from the initial cold pump starts. Below is a typical line of data from each pump.

<u>RCP 2-1</u>

System Pressure	- 1650 psig
2nd Seal Cavity Pressure	- 1034 psig
3rd Seal Cavity Pressure	- 500 psig
Horizontal Vibration	- 3 mils

<u>RCP 2-2</u>

System Pressure	- 1650 psig
2nd Seal Cavity Pressure	- 1075 psig
3rd Seal Cavity Pressure	- 588 psig
Horizontal Vibration	- 3.5 mils

<u>RCP 1-1</u>

Steam Pressure	- 1650 psig
2nd Seal Cavity Pressure	- 1056 psig
3rd Seal Cavity Pressure	- 540 psig
Horizontal Vibration	- 4 mils

<u>RCP 1-2</u>

System Pressure	- 1650 psig
2nd Seal Cavity Pressure	- 920 psig
3rd Seal Cavity Pressure	- 520 psig
Horizontal Vibration	- 3 mils

Based on the above data, B&W felt that all four pumps were
in good operating condition and require nothing more at th
time than periodic monitoring.

B&W has reviewed the results of the operational checks and
has concluded that no detectable damage has occurred to the
pump components. B&W considers the reactor coolant pumps t
be serviceable for sustained full operational conditions
with no requirements for maintenance.

A more detailed analysis was completed to assess the core
thermal conditions during the September 24 depressurization
event at Davis-Besse Unit 1. Core conditions were analyzed
to (1) determine if steam was produced in the core, (2)
determine the maximum internal fuel rod pressure during the
transient, and (3) determine if maximum lift force exceeded
the limit.

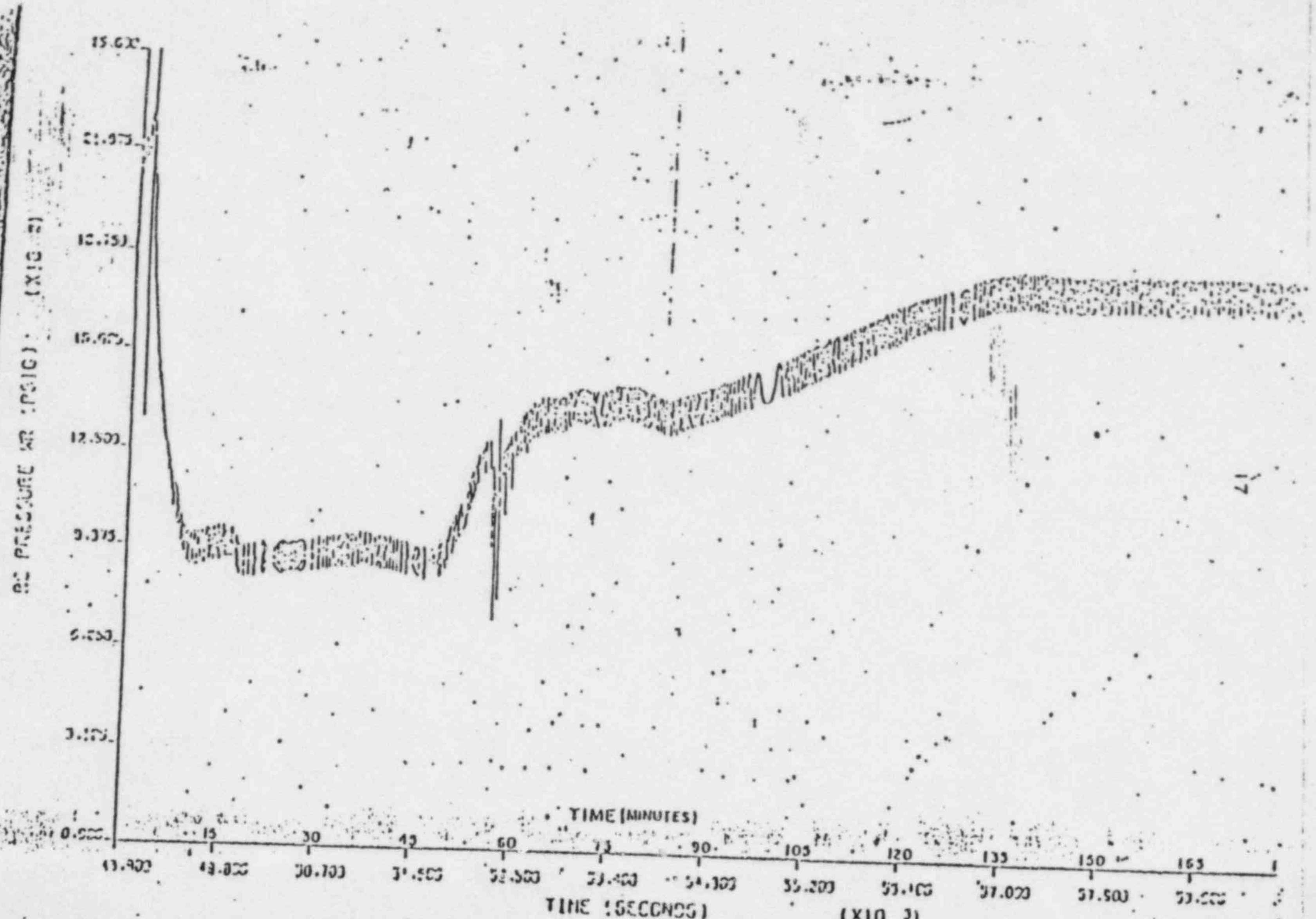
Figure 4-5 shows transient thermal conditions as monitored b
the reactimeter. The system pressure is measured at the
pressure tap, which is approximately 65 feet above the top o
the core. The RC pressure at the top of the core is approxi
mately 50 psi higher than the measured pressure because of
unrecoverable and elevation pressure losses. As shown in
Figure 4-6, the predicted core coolant temperature is slight
higher than the minimum saturation temperature (based upon
measured pressure); however, there is some uncertainty in bo
the measurement and the prediction. Therefore, it is possibl
that some vapor bubble formation (steam bubbles in water) cou
have occurred within the core. An examination of the reactim
data (Figure 4-7) indicates that the RCS pressure level was n
the saturation pressure for less than one hour and that durin
this time period the pressure oscillated with a variation of
± 50 psi. Therefore, the maximum time period during which th
core could have been subjected to bubbly flow was less than o
hour. If bubbles were formed during this period, the formati
would be in the liquid as well as on the surface, as opposed
formation from a hot surface. With the temperatures, time
duration, and type of formation, no significant effect on the
components would be predicted.

Prior to the depressurization event the reactor had been
operating at 15% power for approximately one week. Immediatel
prior to reactor trip the power level was 9% of rated power.
The core burnup was 1 EFPD, therefore no significant fission
gas production had occurred and none was released. During the
60-minute time period in which the indicated RCS pressure was
estimated to vary from 900 to 1000 psia at the top of the core
the average coolant temperature was less than 540° F and no
significant heat generation occurred in the fuel. An initial

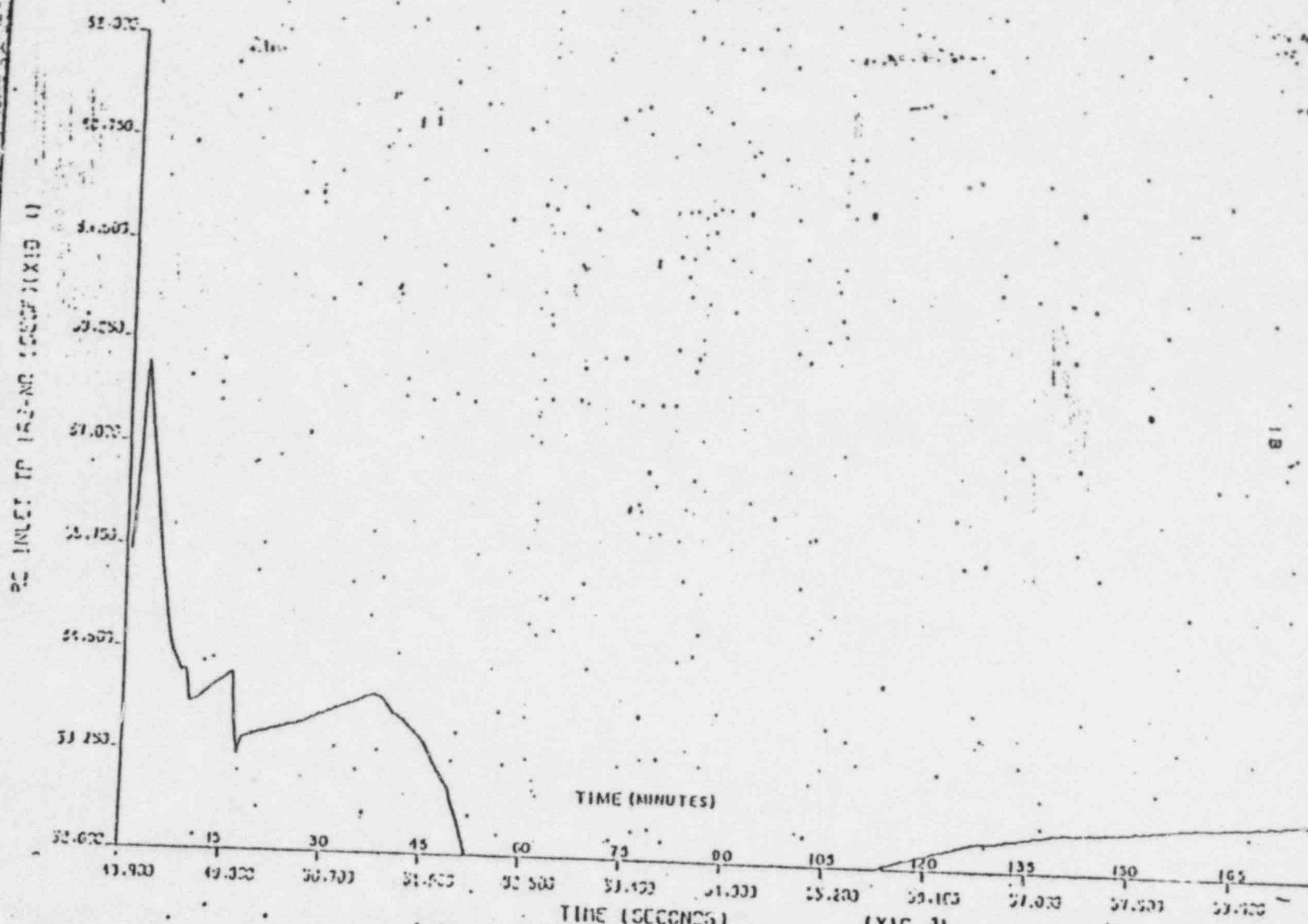
evaluation had predicted tensile stresses in the cladding based upon a maximum pressure differential across the cladding of 200 to 300 psi. This evaluation had been based upon a B&W TAFY analysis with an arbitrary safety factor added to ensure that actual conditions would be bounded by the prediction. A more recent analysis, again using TAFY, has resulted in a predicted maximum internal fuel rod pressure of 1000 psia. This analysis considered as-built fuel properti and hot, near zero power conditions at a coolant average temperature of 540° F. On the basis of this analysis it is concluded that the fuel rod cladding was not subjected to any significant level of tensile stress during the subject depressurization event.

Because the cladding was not subjected to a large, long term tensile stress, no significant long term effects on the claddi resulted. The tensile stresses which could have occurred woul have little effect on the cladding due to the small stress lev and the short duration of the tensile stress.

Assuming a coolant temperature of 537 F and 130 X 10^6 lb/min system flow (per Figures 4-8 and 4-9), the net lift force will be less than 375 lb. The maximum allowable lift force is 472 lb. Therefore, we conclude that fuel assembly lift-off did not occur.



REACTIMETER PLOT TSN-71



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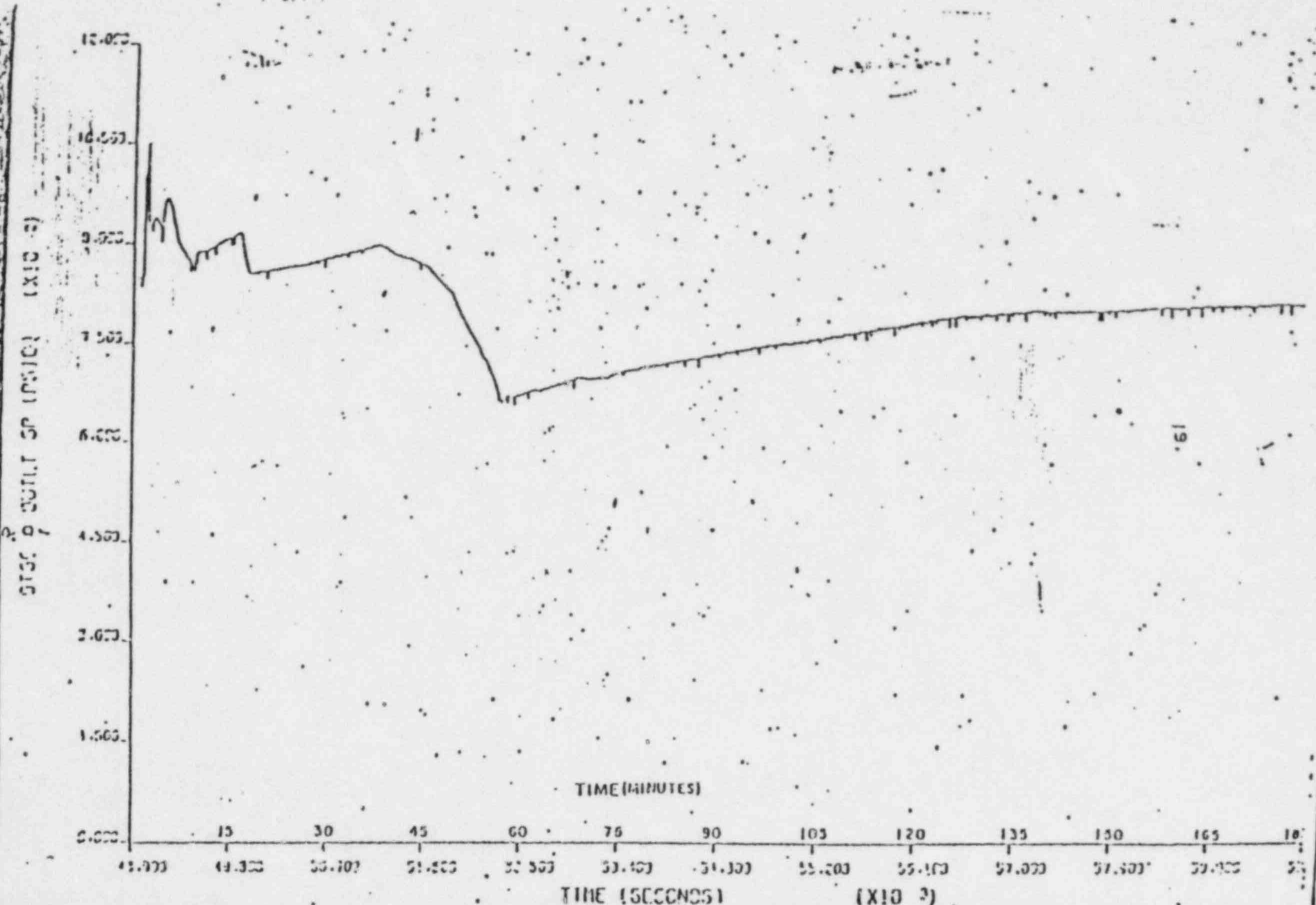
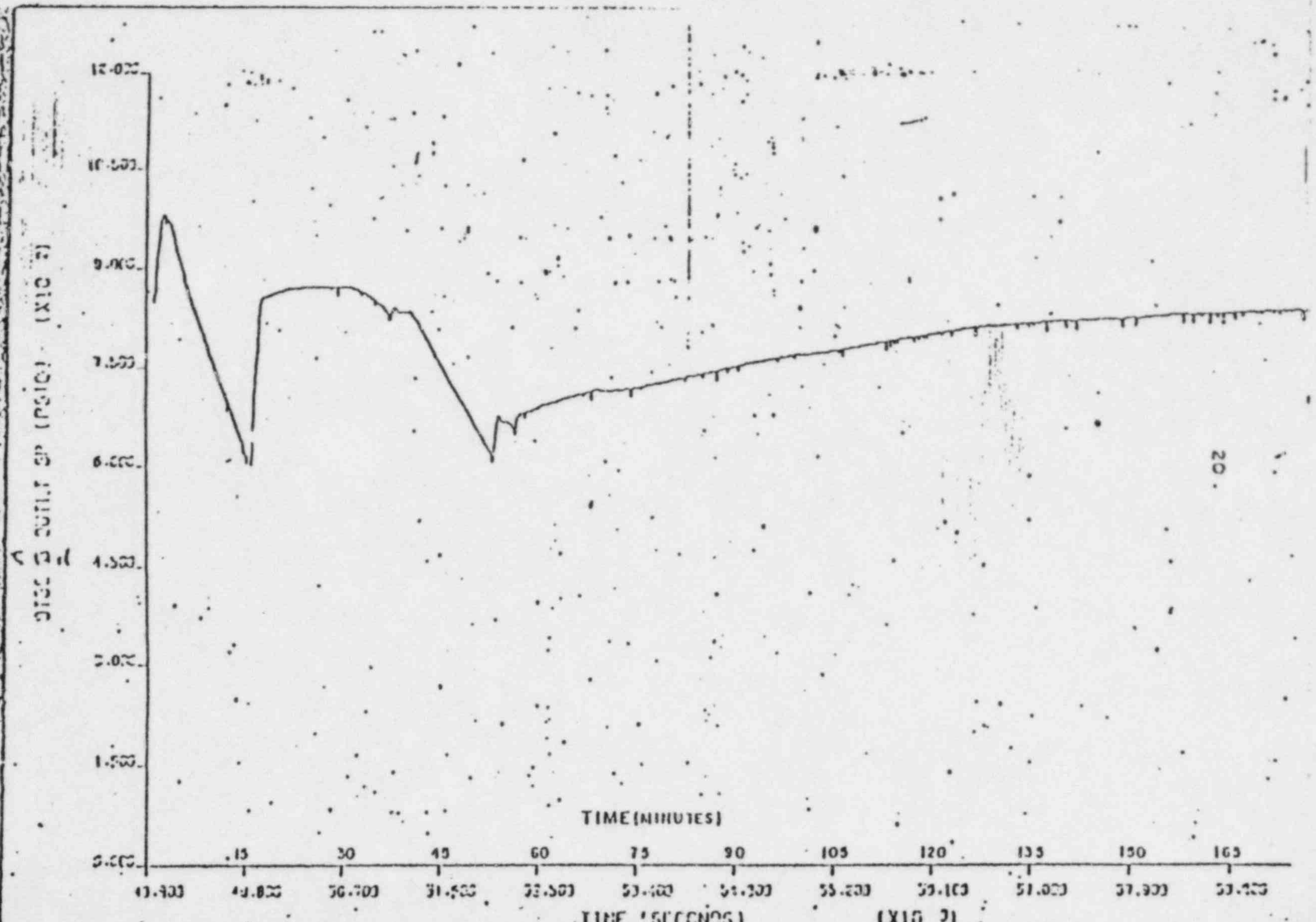


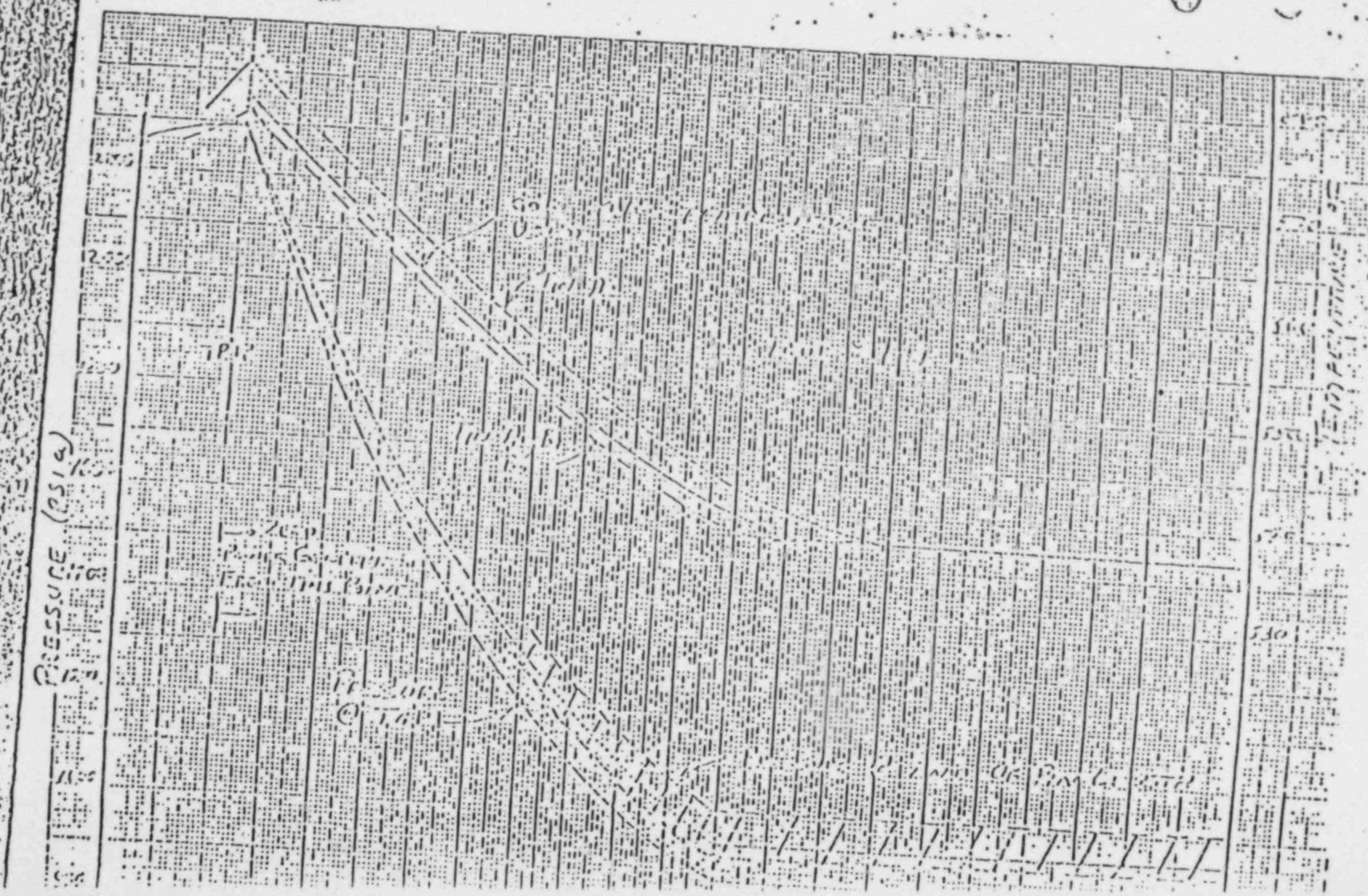
REACTIMETER PLOT TSN=71

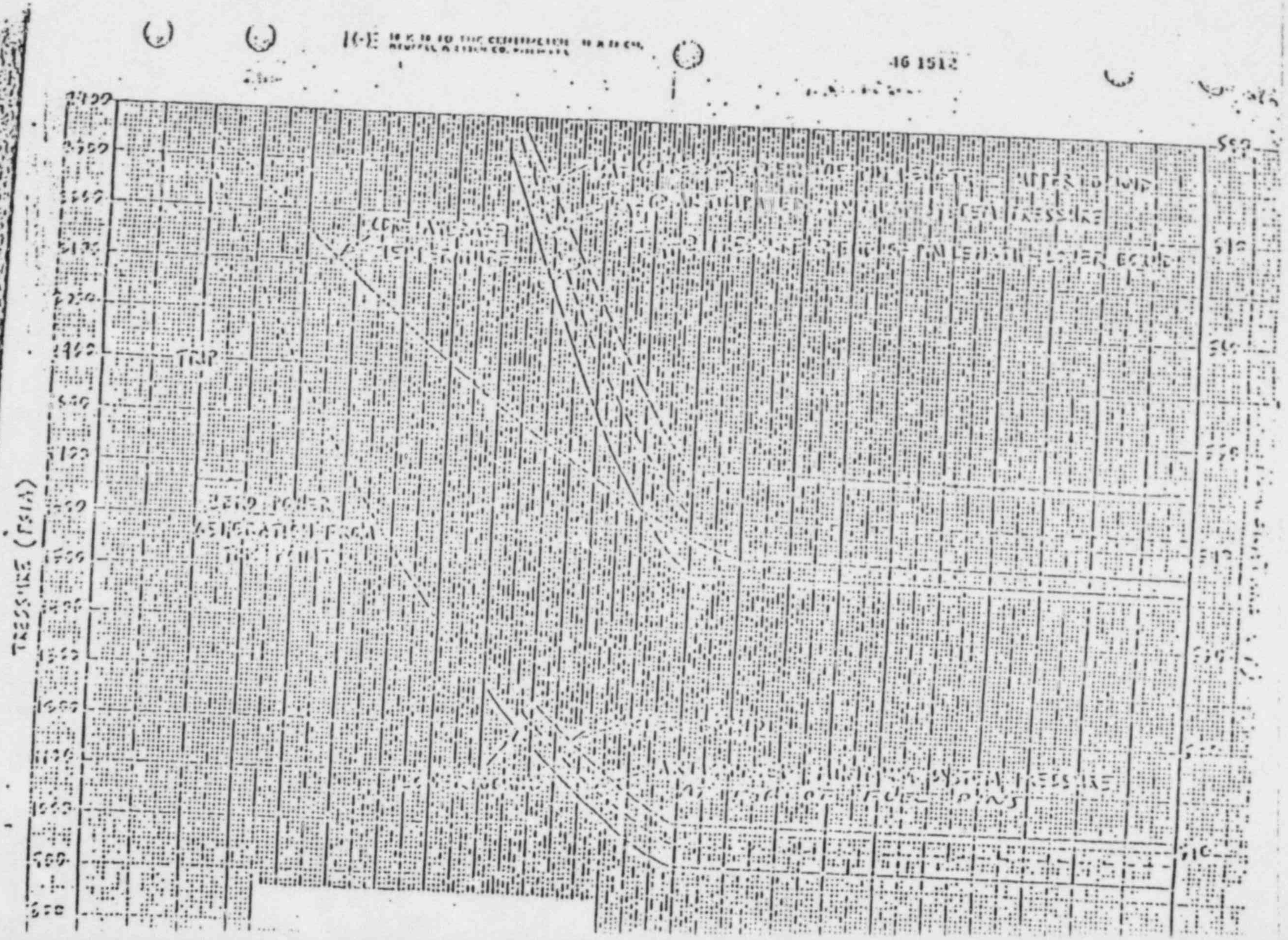
FIGURE 4-3

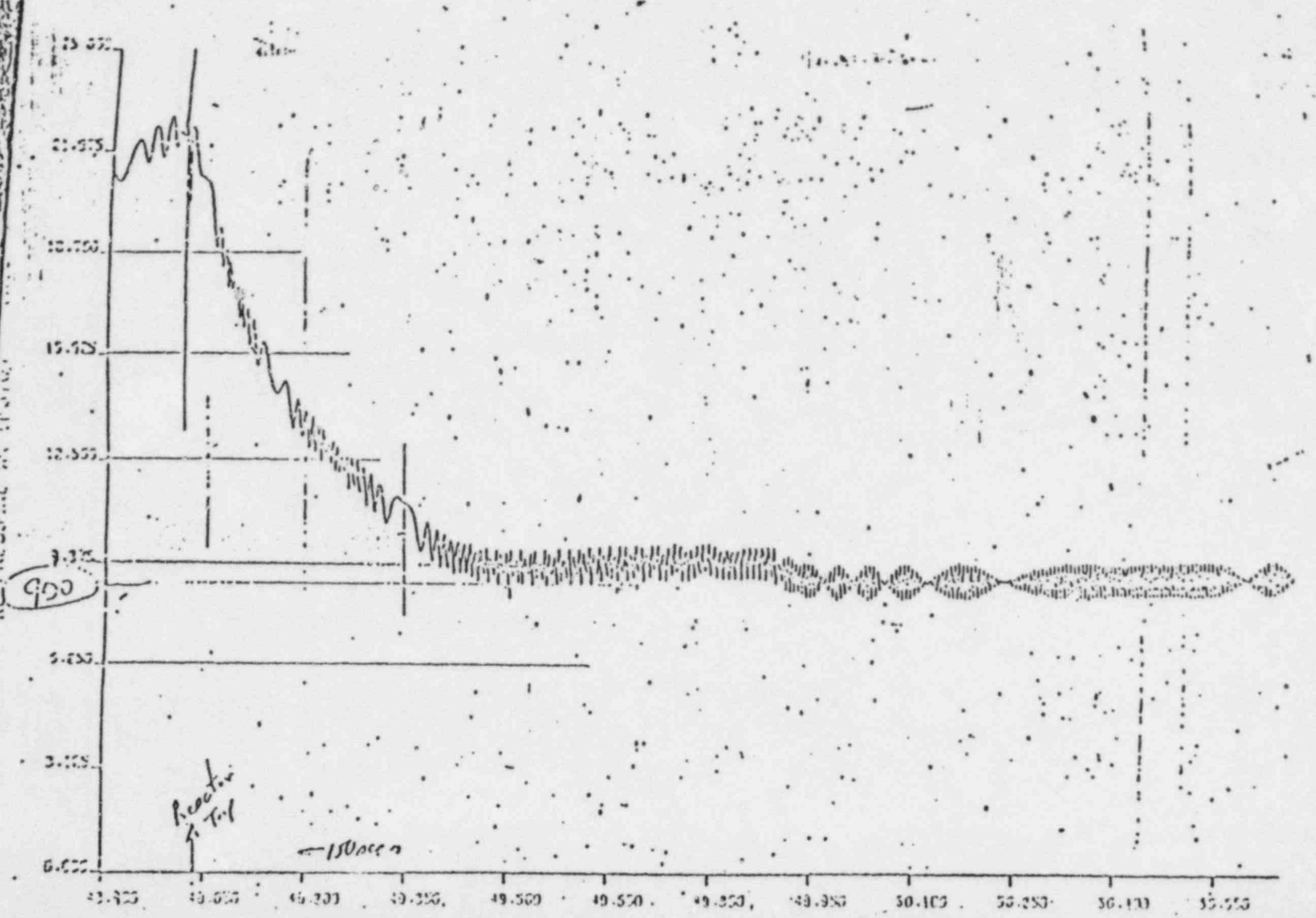


REACTIMETER PLOT TSN=71

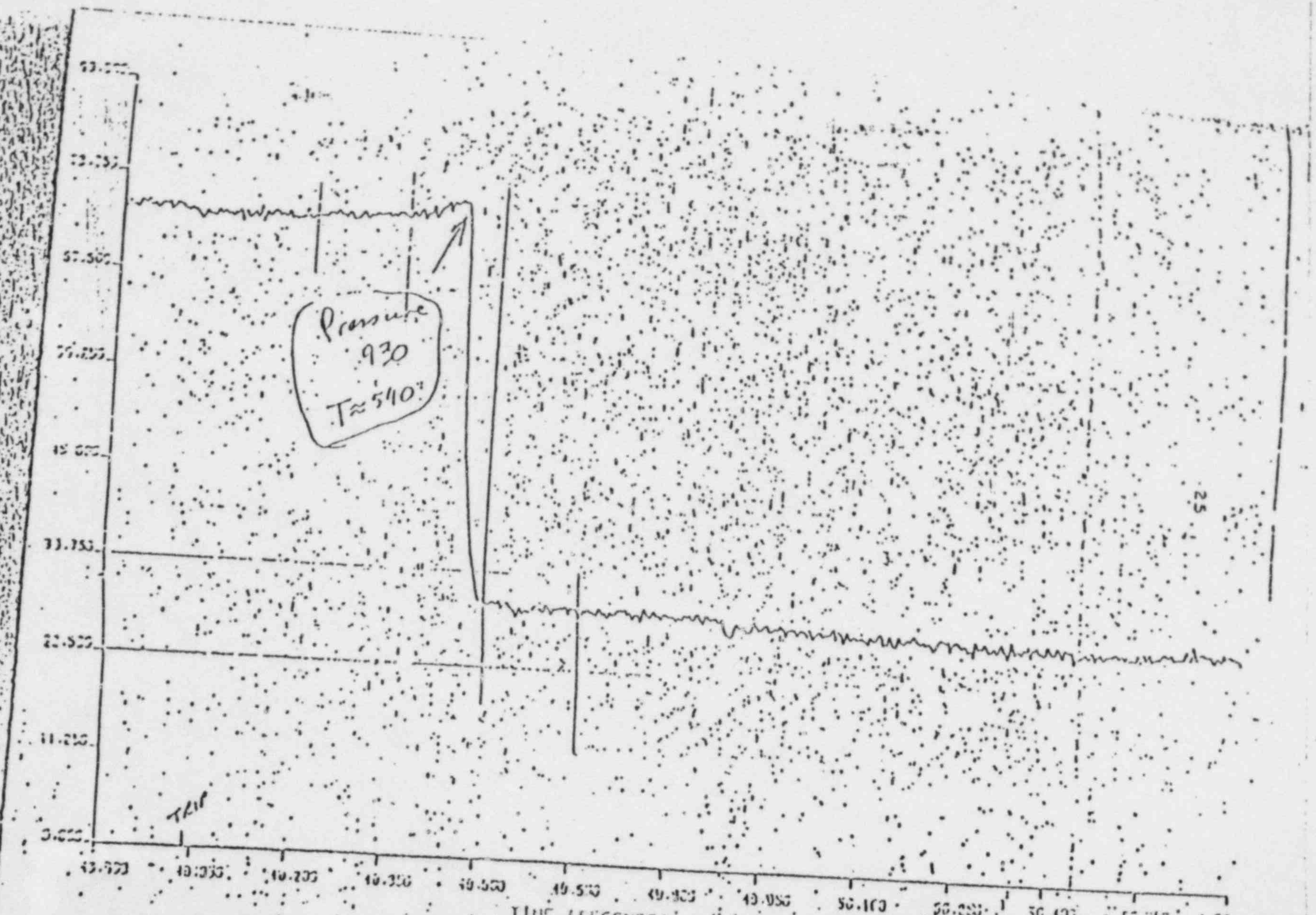
46 1512




46 1512
PRESSURE (PSIA)
TRIP
ZERO POWER



900
Reactor Trip
← 150 sec



Pressure
930
T≈540°
TRIP
25

5. EQUIPMENT DAMAGE, CLEANUP AND REPAIR

A. Entry and Cleanup

Prior to entering containment, air samples were collected at RE5030 (containment air monitor) for radioactive noble gases, particulates, iodines, and tritium; no airborne radioactive materials were detected. When containment was first entered at 0550 on September 25, 1977, to determine the levels of contamination, dirt was found on the walkways on elevation 565' and 585' in the east side of containment, and on 545' elevation the floor was completely covered with dirt which was washed down during the period when steam was being released from the quench tank and condensing on containment structures. The dirt was contaminated with activation products of Cr-51, W-187, Co-58, Zr-97, and Na-24 which were present in the reactor coolant system. Smears of the dirt indicated levels up to 40,000 dpm/100cm^2.

Decontamination was accomplished by shoveling gross amounts of dirt into drums, and vacuum sweeping the remainder. The level of contamination in walkways was reduced to meet clean area limits. Air samples collected during the decontamination work verified that contamination did not become airborne.

The outer surface of steam generator 1-2 was inspected in the region where the metal reflective insulation was blown off. Boric acid stains were observed on the outer surface of steam generator 1-2; however, these minute quantities do not present any concern since the temperature of these surfaces are on the order of 500° F.

B. Equipment Damage

The pressurizer quench tank rupture disc ruptured from high pressure in the quench tank. The steam from the pressurizer quench tank vent damaged metal reflective insulation on the lower part of No. 2 steam generator. A ventilating duct above the quench tank was bent, and a ventilation louver had to be replaced. Several pressurizer heater cables were dampened from the moisture, causing low insulation resistance, and had to be dried out. Four cables were also found shorted to ground, but it is not known if the failures were a direct result of the incident. Two light fixtures and a combustion detector sensor in the quench tank area were also damaged.

Twenty-three (23) panels of reflective insulation were deformed, loosened or detached from the lower exterior of the steam generator. The panels, fabricated from thin stainless steel sheets with air spaces between them, are approximately 36" x 30" x 4".

The panels are formed to the contour of the steam generator and attached to the exterior on a frame to support the weight. Buckles and clips fasten the panels together. Panels blown from the steam generator fell to the floor, piping and ventilation duct in the immediate vicinity. Some panels were repaired and reused; others had to be replaced. The damaged panels were intact but were bent.

C. Repairs

All damaged equipment was repaired or replaced. Instrumentatic and equipment in the area was checked or tested for possible damage from the steam and water.

Twenty-three (23) panels of reflective insulation were replaced The other affected panels were straightened, repositioned and reinstalled on the steam generator.

All essential and automatically-controlled pressurizer heaters were returned to service. The wet pressurizer heater cables were baked, heated or air dried to restore insulation resistanc to vendor recommended values. Only two of the four cables shor to ground were replaced with spares. The other two are on orde:

A new rupture disc was installed on the pressurizer quench tank.

The deformed ventilation duct was straightened and a new louver was installed in the duct.

The damaged light fixture and combustion detector were replaced.

6. SYSTEMS/EQUIPMENT MODIFICATION AND TESTING

A. SFRCS

The Davis-Besse Instrument and Control (I&C) Group has tested logic channels 2 and 4 (channel 2) of the SFRCS, since it was indicated that the closure of SP7A (start-up feedwater valves) led to the sequence of events on 9/24/77. Logic channels 2 and 4 are the only SFRCS channels that actuate SP7A.

On 9/26/77, Maintenance Work Order (MWO) IC-622-77 was written to check the main steam line pressure switches PS 3687A through PS 3687H. A calibration check was completed on 9/27/77. All pressure switches actuated within ±2 psig of the 612 psig setpoints. I&C personnel had nothing to report from the visual inspection.

On 9/27/77, MWO IC-636-77 was written to investigate the remaining inputs to the SFRCS. Pressure differential switches 2686C, 2686D, 2685A and 2685B were tested per ST 5031.14, Section 6.3. The setpoint of the pressure differential switches tested ranged from 176 psig to 187 psig, the setpoint being 177 ±20 psig.

The steam generator level inputs to the SFRCS were tested per ST 5031.14, Section 6.4. Again, logic channels 2 and 4 were tested. All bistables tripped at the desired setpoints. The desired trip setting is .509 ±.013 volts and the range of voltages for the bistables tested were from .5054 volts to .509 volts. In addition, the level transmitter calibration was checked per ST 5031.16. I&C tested for any non-linearities between transmitter input and output, especially at the lower ranges. LT-SP9A5, LT-SP9A9, LT-SP9B6, and LT-SP9B7 were well within the acceptable limits as specified by ST 5031.16 and no non-linearities were observed.

The inputs to the SFRCS from the loss of 4 reactor coolant pumps were not tested since this input actuates auxiliary feedwater only. This input does not affect the feedwater valves or main steam isolation valves.

In addition to testing all the input devices, I&C checked C5792. This is the cabinet for logic channels 2 and 4. All inputs and outputs were normal for existing plant conditions. I&C checked mechanical connections on the input and output buffers, and induced mechanical vibration on the input buffers, output buffers, main logic panels, and output relays without any system effect. The main logic panels were heated slightly with a heat lamp and slowly cooled to check for thermal variations, but this had no effect on the system.

On September 29, I&C completed their check of SFRCS terminations. The following are the results of that check:

1. Screws on TB37 (yellow & blue) were tightened 1/2 of a turn. This is an input to the Sorenson 15 volt logic supply for C5792.

2. In C5721 (Feedwater Panel) one loose screw was found on 21TB11 Terminal 17 (left side of TB). This screw required little movemen to thoroughly tighten. This is a main steam pressure switch input to logic channel 2.

3. In C5721, 21TB27 had 3 loose screws. Terminal 17 (right side of Terminal Board) had to be tightened 1 full turn. This is a main steam pressure switch input to logic channel 3.

   Terminal 18 (right side of Terminal Board) had to be tightened 1/2 a turn. This is a pressure differential switch input to the SFRCS Logic channel 3 Terminal 4 (left side of TB) had to be tightened slightly. This is a main steam pressure switch input to the SFRCS.

On September 30, HIS 4870 A and C were tightened to their mounting. These are stacked switches. The switch units themselves were secure, but the entire package was loose on the mounting. This switch unit being loose would probably not have affected system operation. Temporar jumpers were installed to prevent an inadvertent main steam isolation valve closure during SFRCS checkout.

On October 6, 1977, the Steam Generator level instrumentation was checke out. I&C was specifically looking for noise spikes that could have caused an erroneous trip. All analog inputs and outputs only had a 20 % (typical) AC noise. DC signals appeared "clean".

On October 8, 1977, eight 6 channel chart recorders were patched into the system for continuous monitoring. The recorders were connected per the attached sheets. The system was then checked out for operability. Pressure differential and Steam Generator low level trips were tested. Since the SFRCS was blocked due to low steam pressure, pressure switch trips were initiated and the input to the logic was verified by a voltme reading. These pressure switch inputs will be further tested during the SFRCS monthly, ST 5031.14, Section 6.2, at a later date. Connecting the recorders has indicated no affect on system operability.

LOGIC CHANNEL 1 STRCS TEST CONNECTIONS

INPUT	CONNECT COMMON TO BUFFER	CONNECT COMMON TO TEST POINT	CONNECT SIGNAL LEAD TO BUFFER	CONNECT SIGNAL LEAD TO TEST POINT	RECORDER	CH.
PS3689A	1-1	TP4	1-1	TP5	9.1.48	
PS3689B	2-1	TP2	1-1	TP7	9.1.48	
PS3689C	2-2	TP2	1-1	TP9	9.1.46	
PS3689D	1-2	TP4	1-2	TP5	9.1.48	
PD2685A	1-3	TP4	1-3	TP7	9.1.48	
PD2685C	2-3	TP2	1-3	TP9	9.1.48	
LT SP9B8	1-4	TP4	1-4	TP5	9.1.46	
LT SP9A6	2-4	TP2	1-4	TP7	9.1.46	
15 V. Power Supply Output	1-5	TP2	1-5	TP10	9.1.48	
P681	2-7	TP2	2-7	TP10	9.1.46	1[illegible]
P671	2-6	TP2	2-7	TP16	9.1.46	1[illegible]
LS86	1-6	TP2	1-6	TP10	9.1.49	12

LOGIC CHANNEL II EFRCS TEST CONNECTIONS

[illegible]	CONNECT COMMON TO		CONNECT SIGNAL LEAD TO			
	BUFFER	TEST POINT	BUFFER	TEST POINT	RECORDER	CHA[illegible]
3587A	1-1	TP4	1-1	TP5	9.1.44	
3587B	2-1	TP2	1-1	TP7	9.1.44	
3687C	2-2	TP2	1-1	TP9	9.1.41	
3587D	1-2	TP4	1-2	TP5	9.1.44	
2685A1	1-3	TP4	1-3	TP7	9.1.44	
2685C	2-3	TP2	1-3	TP9	9.1.44	6
SP936	1-4	TP4	1-4	TP5	9.1.41	7
SP9A8	2-4	TP2	1-4	TP7	9.1.41	8
V. Power Supply Output	1-5	TP2	1-5	TP10	9.1.44	9
80	2-7	TP2	2-7	TP10	9.1.41	10
72	2-6	TP2	2-7	TP16	9.1.41	11
96	1-6	TP2	1-6	TP10	9.1.41	12

LOGIC CHANNEL 3 SFRCS TEST CONNECTIONS

INPUT	CONNECT COMMON TO BUFFER	CONNECT COMMON TO TEST POINT	CONNECT SIGNAL LEAD TO BUFFER	CONNECT SIGNAL LEAD TO TEST POINT	RECORDER	CHA[illegible]
PS3689E	1-10	TP4	1-10	TP5	9.1.47	[illegible]
PS3689F	2-10	TP2	1-10	TP7	9.1.47	[illegible]
PS3689G	2-11	TP2	1-10	TP9	9.1.45	2[illegible]
PS3689H	1-11	TP4	1-11	TP5	9.1.47	1[illegible]
PDS2686B	1-12	TP4	1-12	TP7	9.1.47	1[illegible]
PDS2685D	2-12	TP2	1-12	TP9	9.1.47	1[illegible]
LT SP9B9	1-14	TP4	1-13	TP5	9.1.45	19
LT SP9A7	2-13	TP2	1-13	TP7	9.1.45	20
15 V. Power Supply Output	1-14	TP2	1-14	TP10	9.1.47	1[illegible]
P681	2-16	TP2	2-16	TP10	9.1.45	22
P671	2-16	TP2	2-16	TP16	9.1.45	23
LS86	1-15	TP2	1=15	TP10	9.1.45	24

LOGIC CHANNEL 4 SFRCS TEST CONNECTIONS

[illegible]	CONNECT COMMON TO BUFFER	TEST POINT	CONNECT SIGNAL LEAD TO BUFFER	TEST POINT	RECORDER	CH[illegible]
[illegible]3587E	1-10	TP4	1-10	TP5	9.1.43	
[illegible]3657F	2-10	TP2	1-10	TP7	9.1.43	
[illegible]3587G	2-11	TP2	1-10	TP9	060404	
[illegible]3587H	1-11	TP4	1-11	TP5	9.1.43	
[illegible]S2635B	1-12	TP4	1-12	TP7	9.1.43	[illegible]
[illegible]S2686D	2-12	TP2	1-12	TP9	9.1.43	[illegible]
[illegible] SP9B7	1-13	TP4	1-13	TP5	060404	[illegible]
[illegible] SP9A9	2-13	TP2	1-13	TP7	060404	2[illegible]
[illegible]5 V. Power [illegible]upply Output	1-14	TP2	1-14	TP10	9.1.43	2[illegible]
[illegible]680	2-16	TP2	2-16	TP10	060404	2[illegible]
[illegible]672	2-15	TP2	2-16	TP16	060404	23
[illegible]296	1-15	TP2	1-15	TP10	060404	24

On 10/23/77, the SFRCS again tripped from a spurious signal. The St
Feedwater Valve on steam generator No. 2 went closed. This ultimate
resulted in a valid Steam Generator low level trip input to the SFRCS
and the system functioned as intended.

This was the first spurious trip received since the chart recorders h
been connected to the SFRCS. All information on the charts could be
explained except for a problem on SFRCS logic Channel 4 computer alarm
P680. This particular channel on the recorder was intermittently fail
giving spurious trip indications. Of the 48 total chart recorder chan
this was the only one that had failed.

I&C Technicians "checked out" the bad recorder channel for operation.
They found that the channel was sensitive to any mechanical vibration,
it did respond to a given input, and that the pens were slightly misal
From all of the information gathered it was concluded that the indicat
on the bad recorder channel was an input from the SFRCS.

The logic point under question then was the computer point ("P680" Low
Main Steam Pressure Trip). Examining other charts indicated no change
in the input to SFRCS logic Channel 4. Thus it was concluded the probl
was internal to the system. In examining the logic control diagram, it
was determined 3 IC "chips", 2 input buffers and associated wiring coul
have caused the fault. I&C personnel replaced all of the above equipme
with the exception of the interconnecting wiring. The wiring and buffe
connections were visually inspected, and no faults were observed. A
functional logic test was performed and the system responded satisfacto

Power Engineering had contacted Consolidated Controls Corporation, the
manufacturer, and their representative was on site the morning of 10/26/
The manufacturer also recommended changing the same equipment that TECo
I&C personnel had changed.

The manufacturer performed a response time check on both input buffers
in question. The response time test showed no defects. TECo I&C personn
continued to monitor one of the two input buffers in a test set. Failure
of one input buffer did occur on the test set, which indicates that this
was the cause of the half trip.

The manufacturer's representative also took a look at the logic system
with an oscilloscope. He was looking for any erratic, noisy points, but
everything tested appeared to be trouble free. The two input buffers
will remain with TECo for further test and evaluation, while the 3 IC
chips were returned to the manufacturer for evaluation.

The manufacturer's representative on 10/27/77 compiled a list of addi-
tional points they want monitored. TECo I&C personnel are assisting to
connect up the recorders.

After the 10/23/77 event, a study was also conducted to see if any single 120 VAC or 125 V DC fault induced voltage dip could have caused the one-half trip on both MSIV's and closed the SG-2 SU control valve. This study revealed that no single fault on these power supplies could have caused this problem.

The following changes have been made to the design of the SFRCS since the September 24, 1977 incident:

1. Annunciator windows have been added where computer alarms presently exist for:

   a. Steam Generator Level Half/Full Trip for both Channels 1 & 2

   b. Main Feedwater DP Half/Full Trip for both Channels 1 & 2

   c. Loss of 4 Reactor Coolant Pump Trip

2. A new annunciator and computer alarm has been added for a SFRCS Full Trip.

3. The resetting of all SFRCS related alarm will be delayed long enough to allow the computer to record the event.

These changes will be made as soon as possible.

B. Auxiliary Feedpump Turbine Governor

Before describing the modifications made to the auxiliary feedpump turbine (AFPT) governor, the governor action which resulted in the binding will be described. Figure 6-1 is a drawing of the Woodward Governor PG-PL speed setting mechanis showing the governor in the bound up condition. The sequence of events creating this condition is as follows:

1. When the Bodine motor was at a minimum speed setting, the speed setting shaft nut was fully to the left. The link raised the collar, contacting the base speed setting nut, raising it and the "T"-bar to an idle condition. The piv bearing would be contacting the floating lever.

2. Because the governor is not rotating, the speed setting servo remains in a fixed position at idle (as shown). It cannot move until oil pressure is available.

3. The thumbscrew is contacting the low speed stop pin.

4. As the Bodine speed setting motor is rotated toward high speed, the following events occur:

   4.1 The speed setting shaft nut moves towards the high speed stop pin.

   4.2 The link allows the collar to move downward.

   4.3 The collar moving downward, allows the base speed setting nut and "T"-bar assembly to move downward.

   4.4 The floating lever is fixed at the speed setting servo piston end.

   4.5 The low speed stop pin end of the link pushes down on the thumbscrew, which pushes down on the speed setting pilot valve until the dashpot land contacts the dashpot plug.

   4.6 Because the floating lever is now fixed on both ends it stops moving.

   4.7 The "T"-bar continues downward, following the collar. The pivot bearing leaves the floating lever. The "T"-bar continues downward until the retainer screw contacts the floating lever.

   4.8 The collar separates from the base speed setting nut and continues downward until the stop pin in the speed shaft contacts the stop pin in the speed setting shaft nut.

4.9 Because the Bodine motor continues to rotate the manual speed setting knob, slipping the clutch, a torque is placed on the speed setting shaft nut, link and collar. This torque against the "T"-bar causes friction that locks the "T"-bar in place.

5. When the turbine is started, the speed setting servo piston moves downward with increasing oil flow, increasir the speed setting of the governor. When the floating le contacts the pivot bearing, the speed setting pilot valve begins to raise.

6. When the pilot valve control land covers the metering por the speed setting servo piston stops moving.

7. Because the torque is still present on the speed setting shaft, the "T"-bar is bound up, and the governor is at 2200-2600 rpm.

8. When the Bodine speed setting motor is backed off from th stop, the "T"-bar falls down to its high speed stop, drop the pivot bearing. The pilot valve moves downward, incre oil flow to the speed setting servo until the high speed condition is reached.

9. Any changes in speed setting shaft position are now norm followed by the "T"-bar, pivot bearing, pilot valve, and speed setting servo piston.

When the AFPT governors arrived at the Woodward Governor Comp factory, one of the governors was placed on the test stand. observing the operation of the speed setting linkage, it becam evident that a simple link from the speed setting pilot valve (plunger) to the floating lever would allow removal of the be coupling spring, low speed pin, "C" link and dashpot plug in t speed setting pilot valve sleeve (see Figure 2). This would allow the speed setting pilot valve to overtravel when the mot was set in a high speed condition with the speed setting serv at the minimum position (see Figure 6-3).

The required parts were manufactured, the unneeded parts remov and the governors were reassembled. The governors were tested at the Woodward factory and the tests confirmed that the modifications did remove all possibility of the undesired bind ing of the governors. Surveillance testing at the station has also confirmed that the auxiliary feedpump turbine governors function properly.

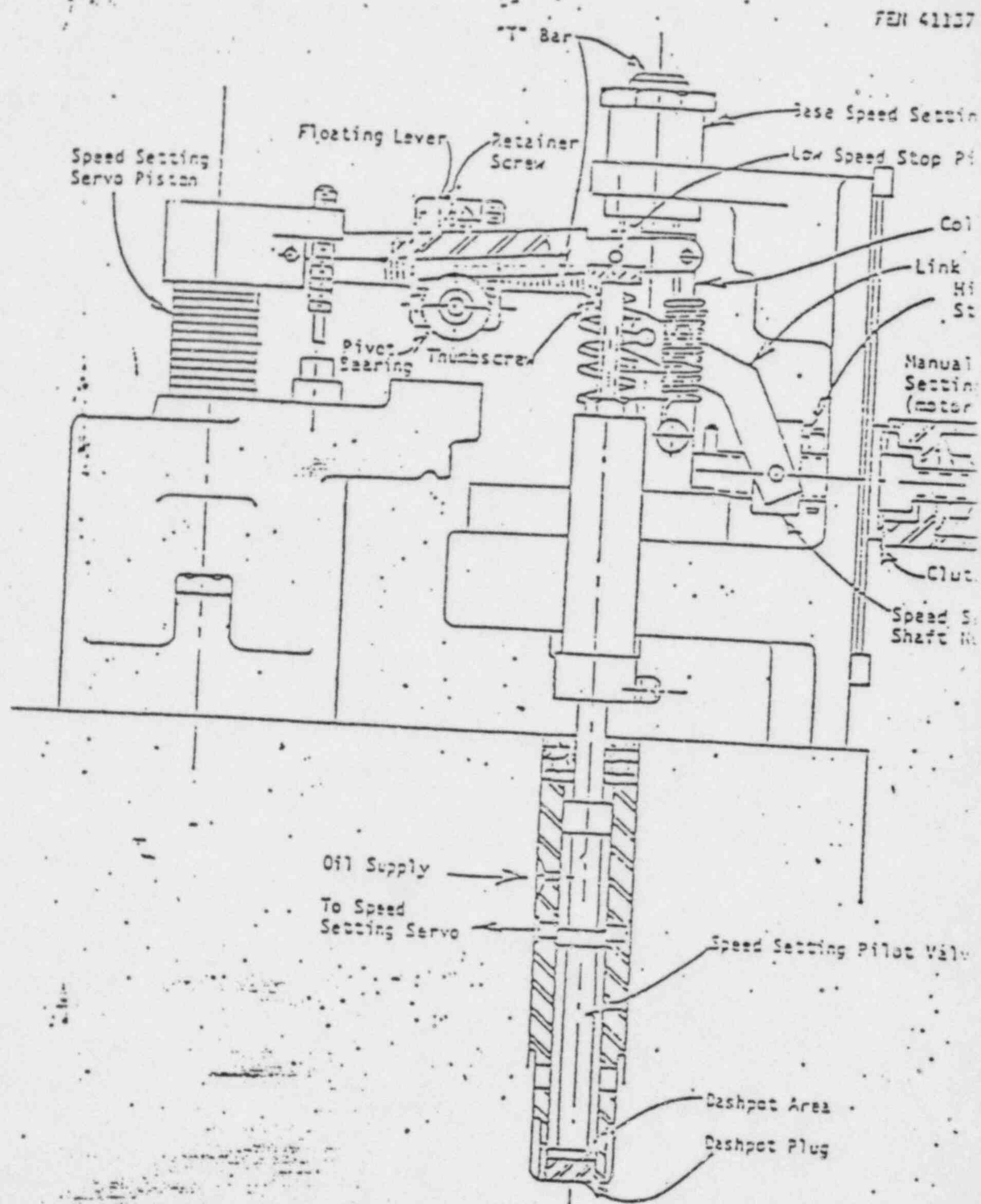

FEN 41137
"T" Bar
Base Speed Settin
Low Speed Stop Pi
Floating Lever
Retainer Screw
Speed Setting Servo Piston
Col
Link
Hi St
Pivot Bearing
Thumbscrew
Manual Setting (motor
Clut
Speed S Shaft M
Oil Supply
To Speed Setting Servo
Speed Setting Pilot Valv
Dashpot Area
Dashpot Plug

FIGURE 6 - 1

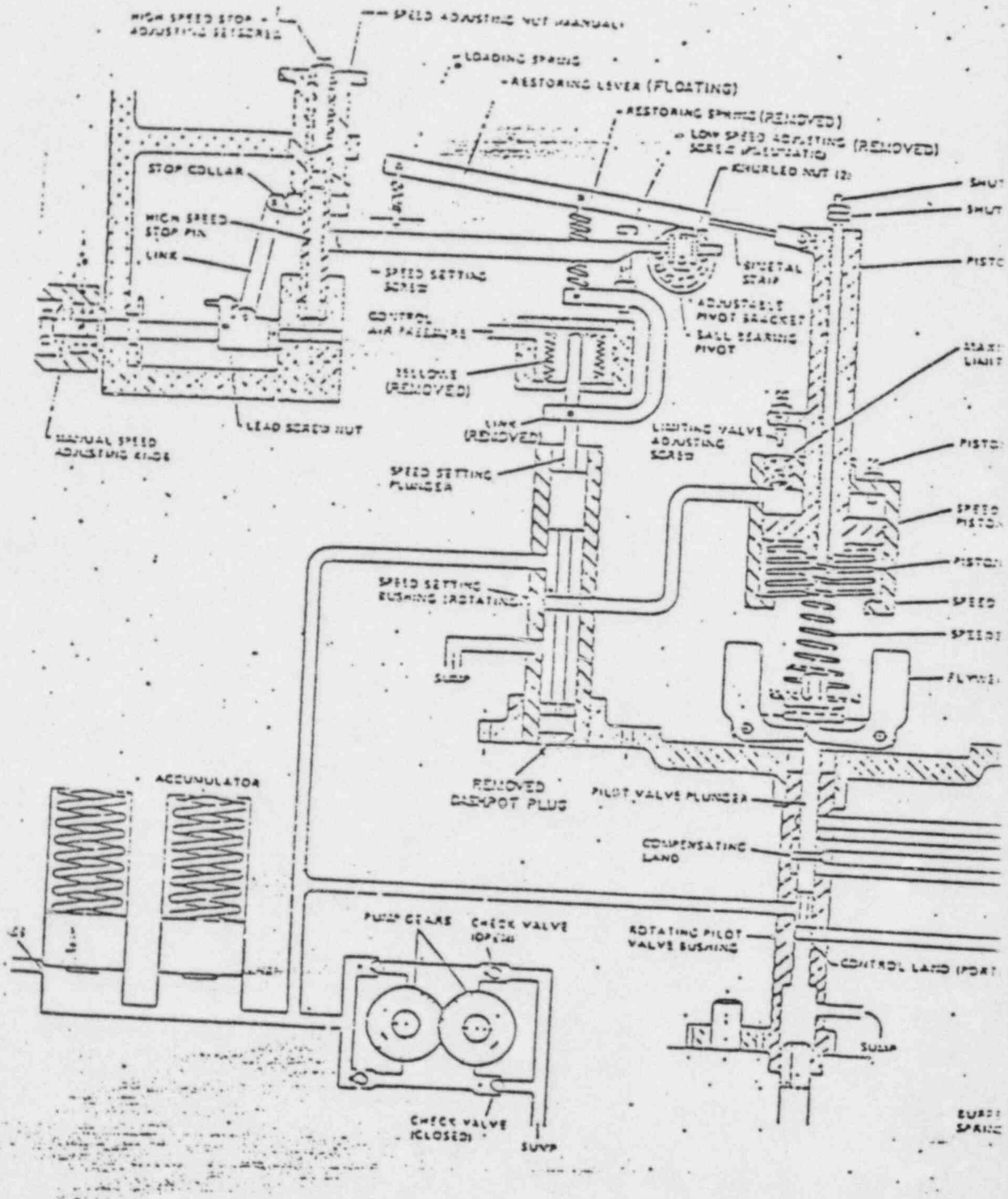
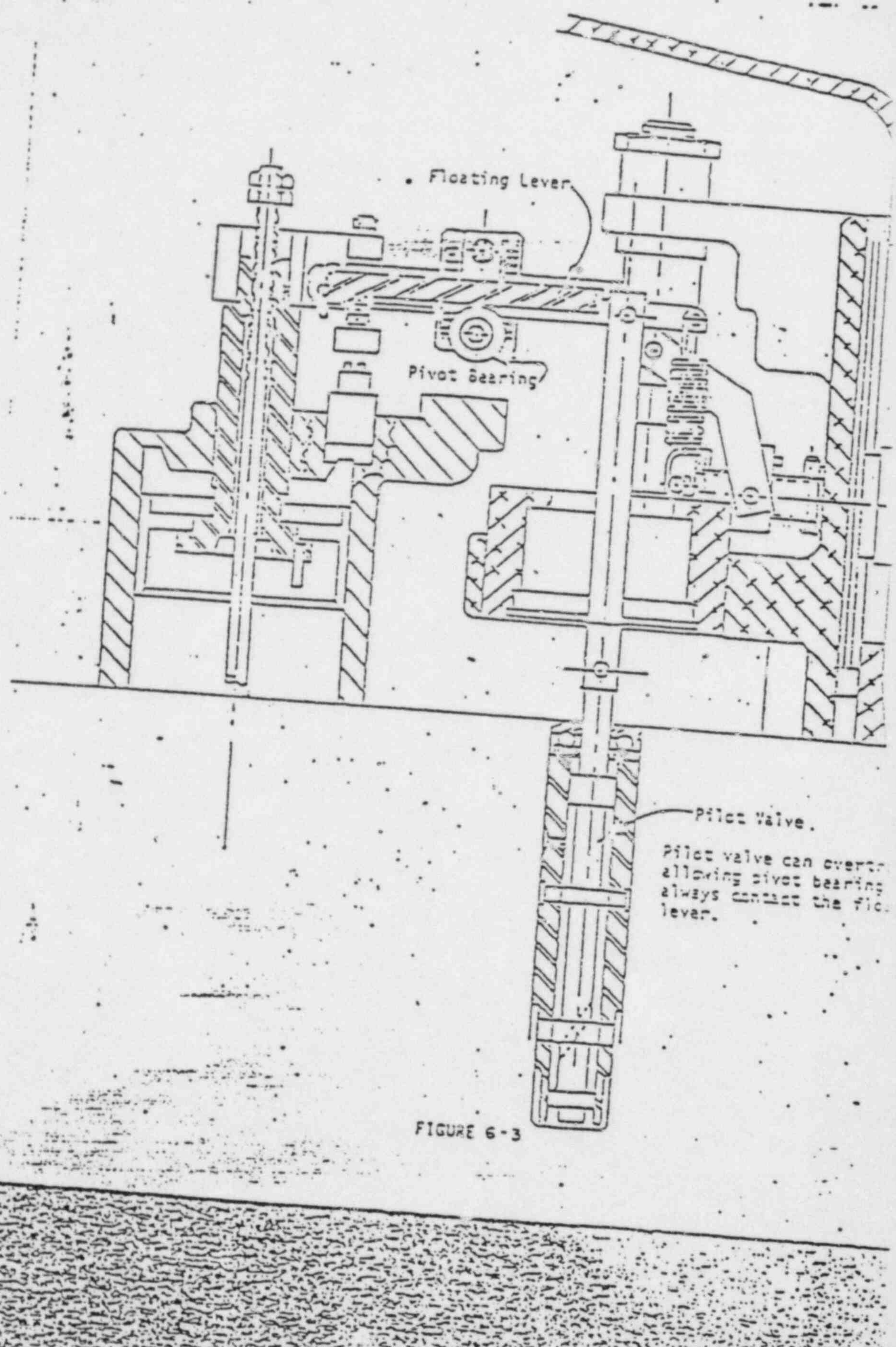

HIGH SPEED STOP ADJUSTING SETSCREW
SPEED ADJUSTING NUT MANUAL
LOADING SPRING
RESTORING LEVER (FLOATING)
RESTORING SPRING (REMOVED)
LOW SPEED ADJUSTING SCREW (REMOVED)
KNURLED NUT (2)
STOP COLLAR
HIGH SPEED STOP PIN
LINK
SPEED SETTING SCREW
BIMETAL STRIP
ADJUSTABLE PIVOT BRACKET
CONTROL AIR PRESSURE
BALL BEARING PIVOT
BELLOWS (REMOVED)
MANUAL SPEED ADJUSTING KNOB
LEAD SCREW NUT
LINK (REMOVED)
LIMITING VALVE ADJUSTING SCREW
SPEED SETTING PLUNGER
SPEED SETTING BUSHING (ROTATING)
SUMP
REMOVED DASHPOT PLUG
PILOT VALVE PLUNGER
ACCUMULATOR
COMPENSATING LAND
PUMP GEARS
CHECK VALVE (OPEN)
ROTATING PILOT VALVE BUSHING
CONTROL LAND (PORT
CHECK VALVE (CLOSED)
SUMP

FIGURE 6-2



Floating Lever
Pivot Bearing
Pilot Valve.
Pilot valve can overtr
allowing pivot bearing
always contact the flo
lever.

FIGURE 6-3

C. Pressurizer Power Relief Valve

On September 28, 1977, the valve was completely disassembled. The main valve was found to be clean. The seats on the nozz. and main valve disc were lapped. The pilot valve was found stuck in the open position and it was thought that the pilot stem was bent so the pilot stem was replaced and the nozzle guide area was cleaned up to remove the marks from the gallir of the foreign material. The valve was reassembled and on October 12, 1977, the valve was stroked six (6) times with a pressurizer pressure of approximately 600 psi. During this testing the pilot valve again stuck and the isolation valve had to be closed.

The valve was again disassembled and under closer observation it was found that the pilot valve stem was moving too far (3/8" vs 1/8" desired). It was also found that the clearance between the pilot stem and the nozzle guide were too small (.0005" vs desired minimum of .001"). The clearances were opened up and the stroke of the pilot was shortened by adjustment of solenoid position. The valve was tested again successfully by stroking it twelve (12) times on October 15, 1977, at a pressurizer pressure of approximately 900 psi and one time at a pressure of 2200 psi.

D. Relay/Fuse/Wiring Checks

Because of the missing relay in the pressurizer electromatic relief valve control circuit, an extensive review program of checking all other relay cabinets was performed. All relay cabinets in the plant were inspected for missing plug-in relays and fuses. A detailed review of drawings was made to determine the service of each missing item and its effect on plant operations. The one additional relay and ten fuses found missing were replaced. There were no essential functior affected by the additional missing relay and fuses. The missing fuses and relay were for generator iso phase bus control, alarm and indications; relay cabinets power supply and heater supply circuits; main feed pump turbine lube oil tank level indication; and reactor coolant pump component cooling water return valve control.

Neither the missing relay nor the fuses were controlled under the station jumper and lifted wire control procedure. This indicates the fuses and relay were removed by unknown persons after checkout and testing.

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6″

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6″

E. Other Actions

Following this incident a training program was developed a presented. This program was approximately eight (8) hours instruction and discussion covering the events of this inci including a detailed coverage of the transient and the acti taken by the operators, and a refresher training session co ing the operation of the steam and feedwater rupture contro system.

The training was presented to all in the operating shift cr the management and staff level engineers and the .A/QC sta

7. EXHIBITS

A. Event Chronology

B. Event Variables Plots

C. SFRCS Description

D. 10 CFR Part 21 Letter on Auxiliary Feedpump Turbine Governor

E. Historical Log

7A Event Chronology

EXHIBIT A

21:34:20 Startup Feedwater Valve to OTSG #2 went closed on a "½ trip" of the Steam and Feedwater Rupture Control System (SFRCS).

21:35:15 Received a complete SFRCS trip due to low level in OTSG #2.

21:35:23 Main Steam Isolation Valves went closed.

21:35:26-49 Pressurizer Power Relief Valve cycled 9 times before sticking open.

21:36:04 Auxiliary Feed Pump (AFP) #1 was feeding #1 Steam Generator (SG). AFP #2 did not come up to full speed (3600 rpm), and the discharge pressure was not sufficient to feed #2 SG.

21:36:07 Operator tripped the reactor.

21:37:17 Safety Features Actuation System Incident Levels 1 and 2 were initiated due to reactor coolant system pressure less than 1600 psi.

21:37:33 High Pressure Injection (HPI) Pump 1-2 was on and had normal flow.

21:37:49 HPI Pump 1-1 was on and had normal flow.

21:38:13 Re-established Reactor Coolant Makeup flow.

21:40:22 Containment Normal Sump Pump came on indicating the Quench Tank Rupture Disk had blown.

21:40:36 HPI Pumps were shutdown.

21:43:16 Auxiliary Boiler System was started and at normal conditions.

21:43:41 Tripped Reactor Coolant Pumps (RCP's) 1-1 and 2-2.

21:44:05 Re-established Reactor Coolant Letdown flow.

21:49:57 Put AFP #2 in hand and ran it up to speed (3600 rpm) and then lowered the speed.

21:58:00 Closed block valve to Pressurizer Power Relief Valve.

22:15:22 Started second Reactor Coolant Makeup Pump.

22:22:57 Started #2 HPI Pump.

22:27:24 Brought #2 Main Feed Pump back on with Auxiliary Boiler steam.

22:27:44 Shutdown #2 HPI Pump.

22:33:23 Shutdown #1 Reactor Coolant Makeup Pump.

22:43:54 Shutdown #1 and #2 AFP's.

EXHIBIT - D

46

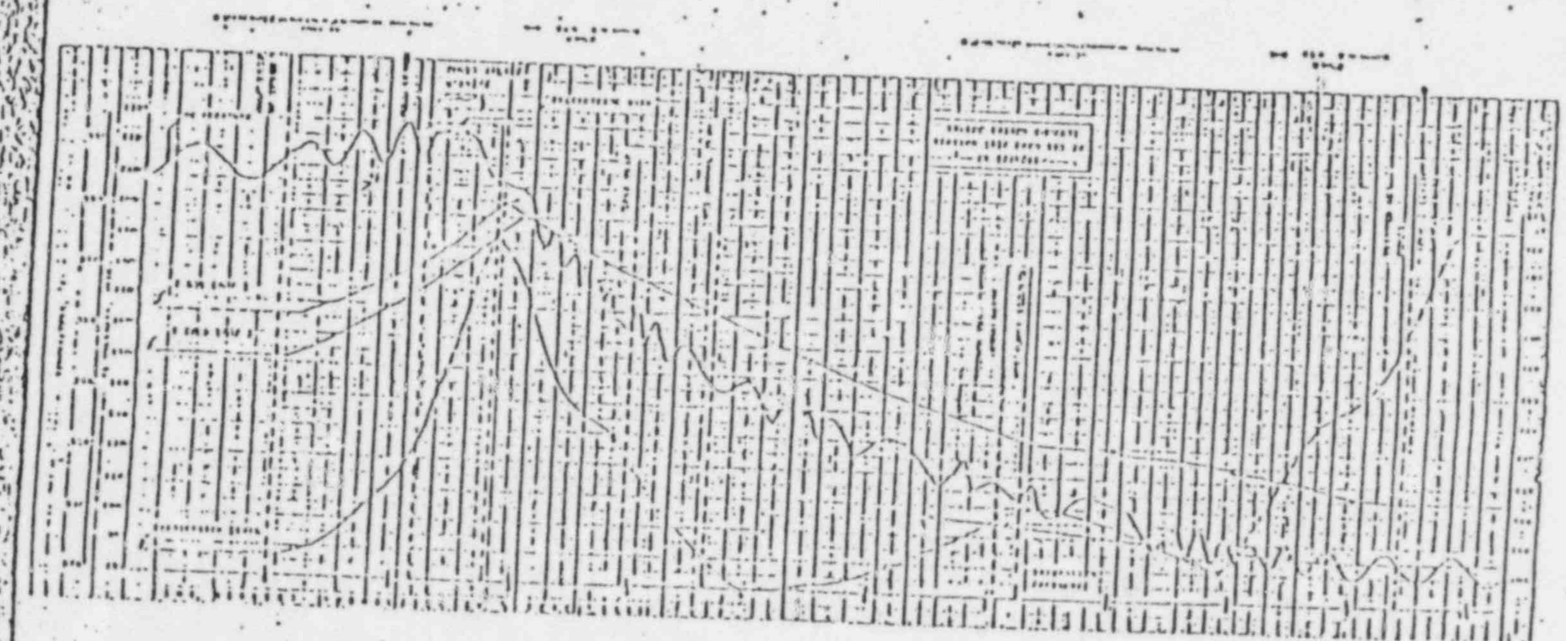
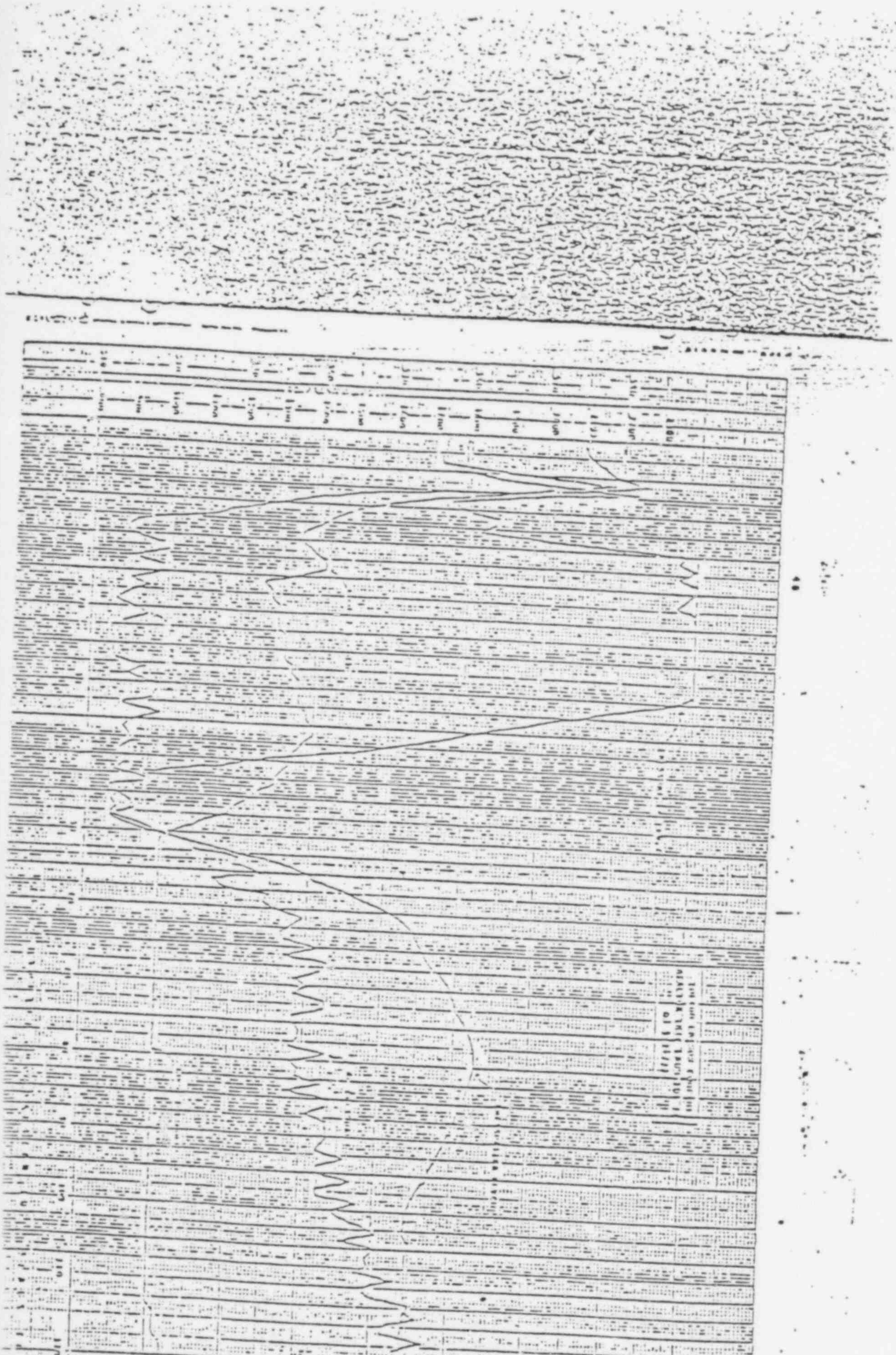
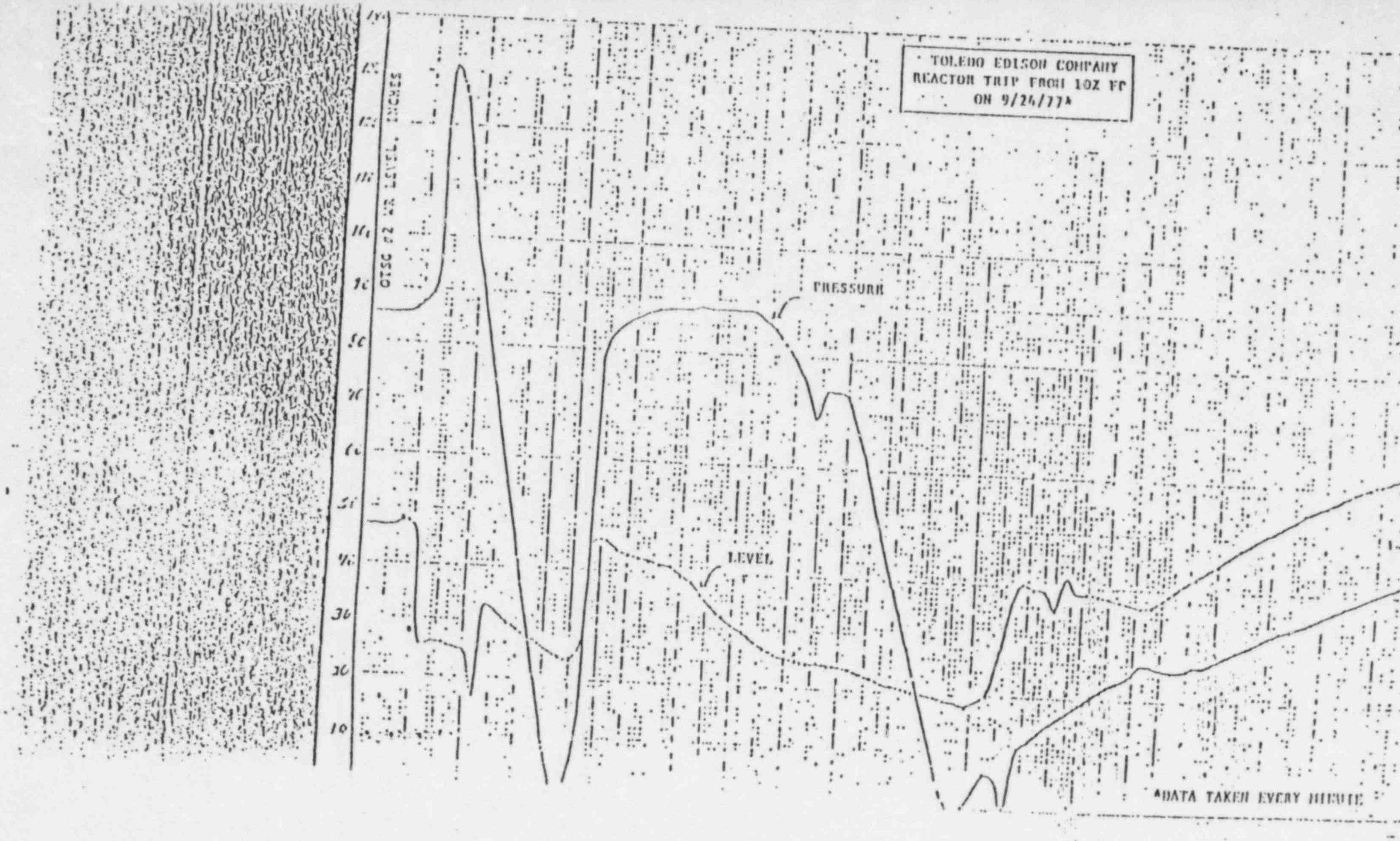
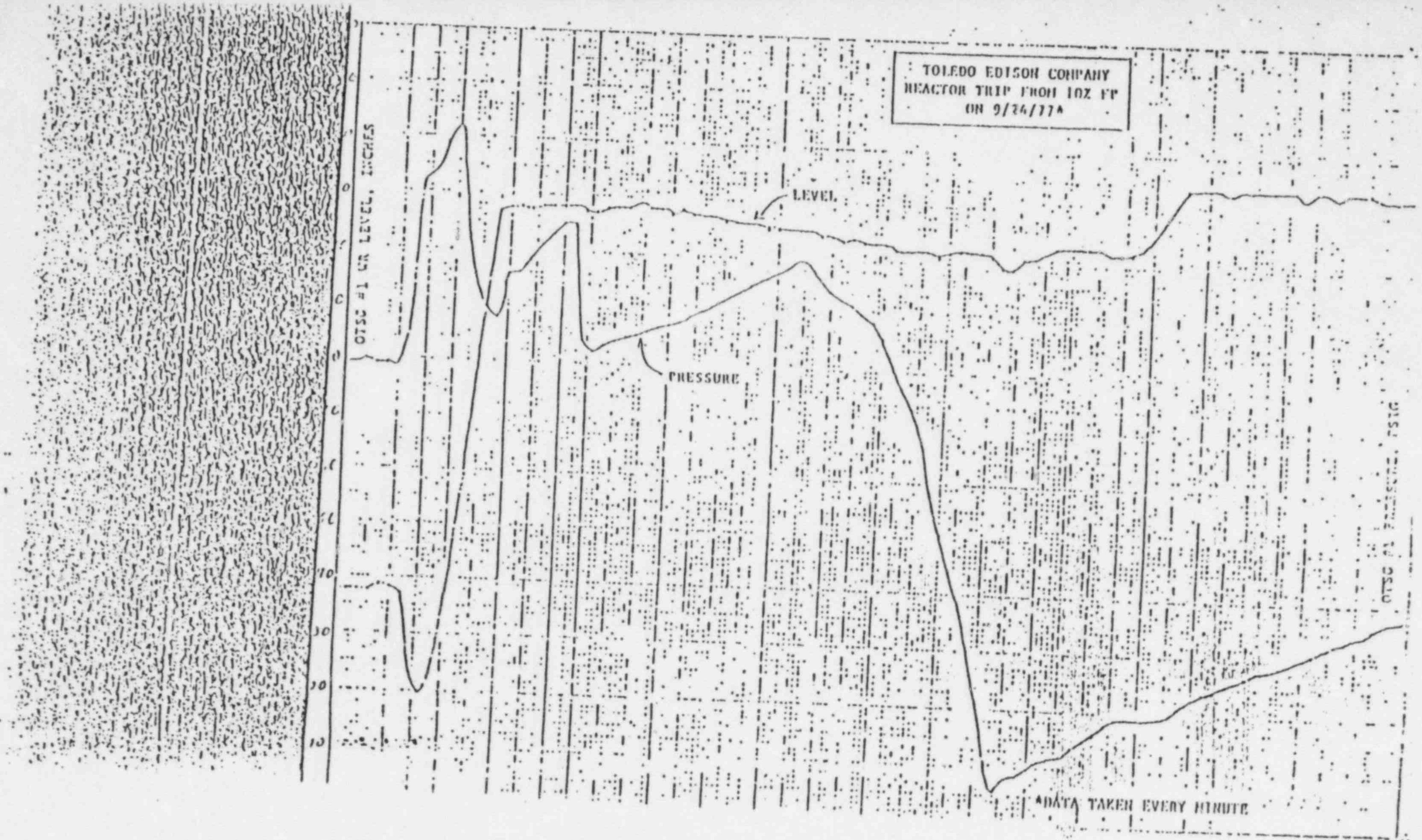


FIGURE 7-1




TOLEDO EDISON COMPANY
REACTOR TRIP FROM 10% FP
ON 9/24/77*
PRESSURE
LEVEL
*DATA TAKEN EVERY MINUTE


TOLEDO EDISON COMPANY
REACTOR TRIP FROM 102 FP
ON 9/24/77*
LEVEL
PRESSURE
OTSG #1 SU LEVEL, INCHES
OTSG #1 PRESSURE, PSIG
*DATA TAKEN EVERY MINUTE

C. System Description

Steam and Feedwater Rupture Control System

1. General

The steam and feedwater rupture control system (SFRCS) is an automatic system designed to protect against the following incidents:

a. Main steam line rupture, either upstream or downstream of main steam isolation valve (MSIV). This condition, if allowed to proceed, could rapidly blow down both steam generators, resulting in a rapid RCS cool down and therefore a rapid reactivity insertion under certain core conditions.

b. Main feedwater line rupture. If on the steam generator side of the feedwater check valve, this is approximately the same accident as the steam line rupture; on the feedwater side of the feedwater check valve this results in a total loss of feedwater.

c. Loss of all feedwater. This (as well as the above incidents) could result in boiling both steam generators dry. If this happens, there would be no steam available for running auxiliary feedwater pumps to remove decay heat.

d. Loss of 4 reactor coolant pumps (RCP). This results in loss of reactor coolant flow and therefore auxiliary feedwater is needed to establish reactor coolant natural circulation flow.

The SFRCS, upon indication of conditions a, b and c above will isolate both steam generators (close the main feedwater valves and main steam line valves and trip the turbine) and start the auxiliary feedwater system. Auxiliary feedwater is initiated to keep steam available for the auxiliary feed pump turbines and to remove decay heat from the reactor coolant system. Once this is accomplished, the operator will have time to begin a cool down in an orderly manner.

2. Design Criteria

The design criteria for the SFRCS and the auxiliary feedwater system are as follows:

a. The system must perform its safety function after a single active failure has occurred. This means that the single failure of any power supply, pump, turbine, instrument or control system logic channel will not prevent the system from removing decay heat from the reactor coolant system.

b. A main steam line break upstream of the MSIV or a main feedwater break downstream of the main feedwater isolation valve will disable one steam generator. After this event both auxiliary feed pumps and turbines will be aligned to the remaining intact steam generator. This remaining steam generator has adequate capacity to remove the decay heat from the reactor coolant system.

3. Functional Description (Refer to Enclosures 1 and 2)

The SFRCS is divided for redundancy, diversity, and testability into four logic channels. Logic channels 1 and 3 form channel 1, and logic channels 2 and 4 form channel 2. In one cabinet one logic channel has an AC power supply, the other a DC supply:

Logic Channel	Cabinet	Power Supply
1	C5762A	Y1 (120V AC)
2	C5792	Y2 (120V AC)
3	C5762A	D1P (125V DC)
4	C5792	D2P (125V DC)

Each logic channel receives the following inputs which will cause it to trip:

a. Six pressure switches, two on each main steam line set at 600 psig decreasing and one on each main steam line set at 650 psig decreasing.

b. Two main feedwater pressure differential switches, one from each main feedwater line (see Enclosure 1 for sensing points) set at 177 psid steam generator pressure higher than main feedwater line pressure.

c. Two level transmitters with bistables, one on each steam generator set at 17" decreasing level on the startup range.

d. A contact from RPS pump power sensing circuit; contact opens on loss of all four RCP's.

The SFRCS cabinets consist basically of an AC and a DC power supply, input buffers, logic modules, and output relays. The output relays de-energize to actuate their associated equipment. They also turn out a light on the cabinet when in the tripped state.

Each input to SFRCS has a test switch and light so that a trip of that input can be initiated for testing purposes.

The outputs from the SFRCS are contacts from the output relays. These contacts are in the control circuits for the SFRCS actuated equipment. Most components require two SFRCS logic channels to trip to actuate. See Enclosure 2 for a listing of actuated equipment.

There is a block feature associated with the low steam pressure trip. To prevent the system from actuating on cooldown, each logic channel has a "block" pushbutton on C5721 and on the SFRCS cabinet. When steam pressure goes below 650 psig a block permissive light is received on C5721 along with annunciator and computer alarms. When the block button is pushed, the channel will not trip on low steam pressure and a "MN STM LOW PRESS TRIP BLKD" light is actuated on C5721 as well as annunciator and computer alarms. On a heatup the block signal is automatically removed when the steam generator

There is another block which is utilized on cooldown. If the decay heat system suction valves from the reactor coolant system (DH11 and 12) are open, this block will prevent the opening of the steam inlet valves to the auxiliary feed pump turbines. This prevents the SFRCS from starting the auxiliary feed pumps when all reactor coolant pumps are secured on shutdown. This "block" is automatically removed when the decay heat system is shut down on startup.

4. System Logic

a. The response of the actuated components depends on the type of trip: (refer to Enclosure 2)

1. On low steam pressure on one main steam line, both steam generators are isolated. In addition, both auxiliary feed pumps are aligned to the steam generator which is above 600 psig.

If both steam generators go below 600 psig, both steam generators are isolated and no auxiliary feedwater is initiated.

If any other trip (such as low steam generator level) accompanies a low steam pressure trip, the valves will align per low steam pressure trip logic.

2. On high feedwater pressure differential or low steam generator level on one steam generator, both steam generators are isolated and each auxiliary feedwater pump is aligned to feed its respective steam generator (1 to 1 and 2 to 2).

3. On loss of all four reactor coolant pumps, each auxiliary feedwater pump is aligned to its respective steam generator The steam generators are not isolated.

4. On all of the above events, the turbine is tripped by the SFRCS.

b. The auxiliary feedwater pump governor control switch in the control room bus has 3 positions:

Auto-Essential (SFRCS)
ICS
Manual

In the auto-essential position, the auxiliary feedwater pump is in auto-essential level control. In the ICS position, the auxiliary feedwater pump is on level control from the ICS; via the Hand-Auto station. In manual, the auxiliary feedwater pump is controlled by the operator with the Raise-Lower switch.

c. The SFRCS starting of the auxiliary feedwater pumps will automatically reset once the trip condition on the input is removed. None of the valves, however, will return to their original position until operated individually from the control room or a new trip condition occurs.

5. System Operation

In order to understand the operation of the SFRCS system, it is best to follow the various system actions under several accident conditions. The following cases will be considered:

a. Steam Line Rupture
b. Feedwater Line Rupture
c. Loss of Feedwater Pumps
d. Loss of Four Reactor Coolant Pumps

Enclosures 1 and 2 should be used as an aid to understanding the description. All discussions assume 100% FP operation at start. Some non-SFRCS actions are considered to aid in understanding the transient.

(1) Steam Line Rupture - Assume steam line 1 shears downstream of MSIV. Steam pressure will rapidly drop. When either steam generator reaches 600 psig, all four logic channels will trip, isolating both steam generators. (See Enclosure 2 for specific valves.) The MSIV takes five seconds to shut, the main feedwater isolation valve 15 seconds. Both steam lines will probably drop below 600 psig, therefore, auxiliary feedwater will not start until one steam generator recovers to above 600 psig. Auxiliary feedwater pumps will align as described in Section 3 above to feed the steam generator that first recovers to 600 psig, with both auxiliary feed pumps. The SFRCS will trip the turbine. The reactor will trip on low pressure.

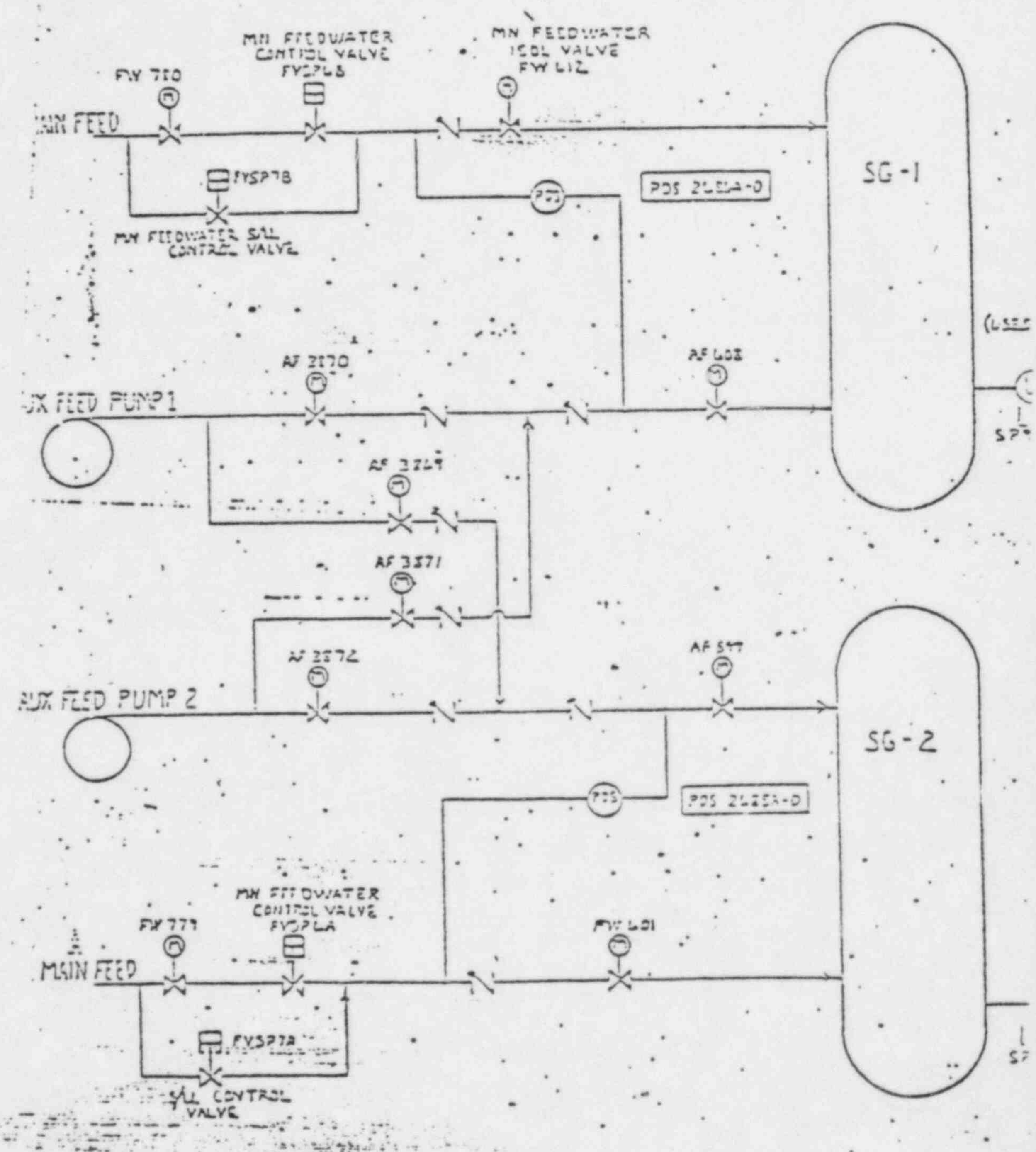
When both steam generators are above 600 psig, the trip condition automatically clears and the atmospheric vent valves may be used for pressure control cooldown if required and provided no other trips are present.

(2) Feedwater Rupture Line - Assume feedwater line 1 shears upstream of the feedwater line check valve. Feedwater pressure will rapidly drop. When either feedwater heater drops to 177 psig less than steam generator pressure, the SFRCS will isolate both steam generators and align the auxiliary feed pumps to their respective steam generator (1 to 1; 2 to 2). The reactor will trip on high pressure and the SFRCS will trip the turbine.

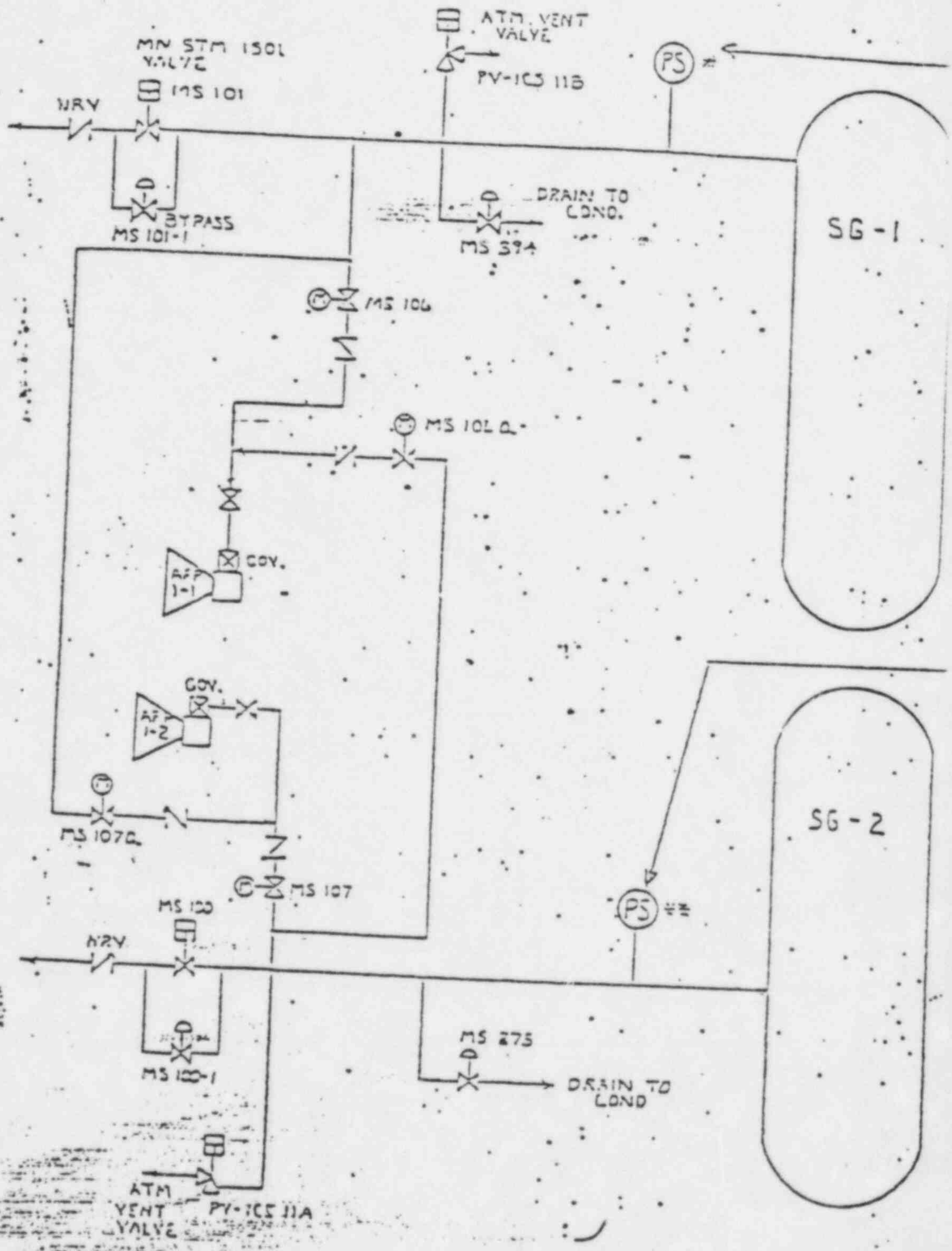
(3) Loss of Four Reactor Coolant Pumps - If all four reactor coolant pumps trip, the turbine will be tripped by the SFRCS and the reactor protection system will trip the reactor. The SFRCS will initiate auxiliary feedwater. The steam generators will not be isolated.

ENCLOSURE 1 SFRCS ACTUATED EQUIPMENT (FEEDWATER)

(FOR STEAM VALVES SEE NEXT PAGE)



ENCLOSURE 2 SFRCS ACTUATED EQUIPMENT (STEAM)



ENCLOSURE 2

STEAM-FEEDWATER RUPTURE CONTROL SYSTEM ACTUATION

CHANNEL 1 (C 5762A) / CHANNEL 2 (C 5792)	MS 101 / MS 101	MS 100 / MS 100	MS101-1 NOTE 3	MS100-1 NOTE 3	MS 394 NOTE 3	MS 375 NOTE 3	ICS 11B NOTE 3	ICS 11A NOTE 3	FW 612	FW 601	FW 780	FW-779	SP 7B NOTE 3	SP 7A NOTE 3
LOW PRESSURE MAIN Steam Line 1 (<600#)	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT
LOW PRESSURE MAIN Steam Line 2 (<600#)	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT
SG - FW ΔP SG 1 HIGH (>177 PSID)	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT
SG - FW ΔP SG 2 HIGH (>177 PSID)	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT
LOW LEVEL SG 1 (<17" SUB)	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT
LOW LEVEL SG 2 (<17" SUB)	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT
LOSS OF 4 RC PUMPS	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT	SHUT*	SHUT

CHANNEL 1 (C 5762A) / CHANNEL 2 (C 5792)	SP 6A	SP 6B	MS 106	MS 107	MS 106A	MS107A	AF3870	AF3872	AF 3869	AF3871	AF 608	AF 599	MAIN TURBINE
LOW PRESSURE MAIN STEAM LINE 1 (<600#)	SHUT	SHUT	SHUT	OPEN NOTE 1	OPEN NOTE 1	SHUT	SHUT	OPEN NOTE 1	OPEN NOTE 1	SHUT	SHUT	OPEN	TRIP
LOW PRESSURE MAIN STEAM LINE 2 (<600#)	SHUT	SHUT	OPEN NOTE 1	SHUT	SHUT	OPEN NOTE 1	OPEN NOTE 1	SHUT	SHUT	OPEN NOTE 1	OPEN	SHUT	TRIP
SG-FW ΔP SG 1 HIGH >177 PSID	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	TRIP
SG-FW ΔP SG 2 HIGH >177 PSID	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	TRIP
LOW LEVEL SG 1 (<17" SUB)	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	TRIP
LOW LEVEL SG 2 (<17" SUB)	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	TRIP
LOSS OF 4 RC PUMPS			OPEN NOTE 2	OPEN NOTE 2	SHUT	SHUT	OPEN	OPEN	SHUT	SHUT	OPEN	OPEN	TRIP

NOTES:

1. If both main steam lines are <600#, these valves shut.
2. These valves will not open if DH 11 and DH 12 (DH Suction from RCS) are open.
3. These valves are closed on a ½ channel trip.