NRC FORM 366
(7-77)

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U. S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT

CONTROL BLOCK: ① (PLEASE PRINT OR TYPE ALL REQUIRED INFORMATION)

01 — LICENSEE CODE: MNPIN1 ② — LICENSE NUMBER: 00-00000-00 ③ — LICENSE TYPE: 41111 ④ — CAT: ⑤

CON'T 01 — REPORT SOURCE: L ⑥ — DOCKET NUMBER: 0500282 ⑦ — EVENT DATE: 100279 ⑧ — REPORT DATE: 101679 ⑨

EVENT DESCRIPTION AND PROBABLE CONSEQUENCES ⑩

02 See attached report

03

04

05

06

07

08

09 — SYSTEM CODE: HJ ⑪ — CAUSE CODE: E ⑫ — CAUSE SUBCODE: B ⑬ — COMPONENT CODE: HTEXCH ⑭ — COMP. SUBCODE: F ⑮ — VALVE SUBCODE: Z ⑯

⑰ LER/RO REPORT NUMBER — EVENT YEAR: 79 — — SEQUENTIAL REPORT NO.: 027 — / — OCCURRENCE CODE: 01 — REPORT TYPE: T — — — REVISION NO.: 0

ACTION TAKEN: X ⑱ — FUTURE ACTION: X ⑲ — EFFECT ON PLANT: A ⑳ — SHUTDOWN METHOD: C ㉑ — HOURS ㉒: 0384 — ATTACHMENT SUBMITTED: Y ㉓ — NPRD-4 FORM SUB.: N ㉔ — PRIME COMP. SUPPLIER: N ㉕ — COMPONENT MANUFACTURER: W120 ㉖

CAUSE DESCRIPTION AND CORRECTIVE ACTIONS ㉗

10 See attached report

11

12

13

14

15 — FACILITY STATUS: E ㉘ — % POWER: 100 ㉙ — OTHER STATUS ㉚: NA — METHOD OF DISCOVERY: A ㉛ — DISCOVERY DESCRIPTION ㉜: See attached report

16 — ACTIVITY RELEASED: M ㉝ — CONTENT OF RELEASE: M ㉞ — AMOUNT OF ACTIVITY ㉟: See attached report — LOCATION OF RELEASE ㊱: See attached report

PERSONNEL EXPOSURES

17 — NUMBER: 000 ㊲ — TYPE: Z ㊳ — DESCRIPTION ㊴: NA

PERSONNEL INJURIES

18 — NUMBER: 000 ㊵ — DESCRIPTION ㊶: NA

LOSS OF OR DAMAGE TO FACILITY ㊸

19 — TYPE: B ㊷ — DESCRIPTION: See attached report

PUBLICITY

20 — ISSUED: Y ㊹ — DESCRIPTION ㊺: Press conference held on 10/2 @ 1900 NSP office — NRC USE ONLY

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NSP

PRAIRIE ISLAND NUCLEAR GENERATING PLANT

Red Wing, Minnesota

UNITS 1 AND 2

POOR ORIGINAL

PRAIRIE ISLAND UNIT 1

STEAM GENERATOR TUBE BREAK

LICENSEE EVENT REPORT

October 16, 1979

NORTHERN STATES POWER COMPANY
MINNEAPOLIS, MINNESOTA

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A. INTRODUCTION

On October 2, 1979, a tube break occurred in #11 steam generator of the Prairie Island Nuclear Generating Plant, Unit 1. This event is being reported in accordance with Technical Specification Section 6.7.B.1 (c) in that an abnormal degradation of the reactor coolant pressure boundary occurred. This report describes the event and subsequent analysis in detail since the break, due to mechanical wear, is expected to be of interest to the nuclear industry. It should be noted that all engineered safety systems functioned as designed and the plant operating staff accomplished safe reactor shutdown, steam generator isolation, and RCS cooldown in an expeditious manner following existing operating procedures.

This report addresses the following topics:

1. Regulatory and Offsite Agency Notification
2. Operational Sequence of Events
3. RCS Parameter Behavior - Short Term
4. RCS Parameter Behavior - Long Term
5. Natural Circulation Cooldown
6. RCS Leak Rate Determination
7. Radioactive Releases
8. Offsite TLD Measurements
9. RCS Iodine-131 Activity Behavior
10. Steam Generator Inspection and Cause Identification
11. Corrective Actions
12. Comparison of FSAR analysis and actual break results
13. Recommendations

Additional reports on this event, 79-27, may be issued if appropriate.

B. REGULATORY AND OFFSITE AGENCY NOTIFICATION

Notifications associated with this event were prompt. The Emergency Director declared a site emergency at 1430. Offsite notifications are not required for a site emergency; however, the Emergency Director, being cognizant of the FSAR analysis, deemed the event significant enough to alert the offsite agencies of the potential for possible offsite consequences. All offsite contacts required for a general emergency were alerted. The following are several of the offsite agencies contacted:

(a) Minnesota Department of Emergency Services (1432)
(b) NRC Emergency Response Center, Bethesda, and the Region III I & E Director (1433)
(c) NSP General Manager of Power Production (1445)

The Governor of the State of Minnesota was notified of the event at 1432.

The NRC I & E Site Inspector heard the announcement of the reactor trip at 1424 and was in the control room within one minute of the event.

A Minnesota Department of Health Emergency Response Team was dispatched and arrived at the site environs at approximately 1700.

The Region III I & E Emergency Response Team arrived on the site at approximately 1830.

The site emergency was terminated at 2200 on October 2.

C. OPERATIONAL SEQUENCE OF EVENTS

The following is a chronological sequence of events that occurred from the first indication of the steam generator tube break until the leaking tube was identified.

Date	Time	Event
Oct 2	1414	High Radiation alarm on 1R15 (air ejector discharge gaseous radiation monitor)
	1420	Overtemperature ΔT Turbine Runback due to decreasing pressure
	1421	Low Pressurizer pressure (< 2139.9 psig)
	1421 (approx)	Commenced load reduction
	1422	Low pressurizer level (< 18.3%)
	1423	Started second charging pump (#11)
	1424 (approx)	Started third charging pump (#13)
	1424:09	Reactor trip for "Low Pressurizer Pressure" (< 1900 psig)
	1424:14	Safety injection occurred due to "Low Pressurizer Pressure (< 1815 psig)
	1424:33	Minimum RCS water inventory; RCS pressure begins increasing
	1426	11 Reactor Coolant Pump stopped
	1427	12 Reactor Coolant Pump stopped
	1432:29	11 Steam Generator level increased above the "Lo Lo Level" setpoint (13%) on the narrow range after having gone offscale low after the trip (It is normal for SG Level to go offscale low on a trip; recovery in this case was much more rapid than usual)

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Date	Time	Event
Oct 2	1438	SI Reset
	1441	Loop A MSIV closed
	1456	Pressurizer Level returned on scale
	1456	Stopped 12 SI pump
	1456-57	Began depressurization of the RCS using the pressurizer PORV. (The valve was cycled 6 to 8 times to reduce pressure to required value)
	1502	Pressurizer level reached the high level setpoint (> 55%)
	1506	11 SI Pump stopped
	1507	Pressurizer Relief Tank rupture disc relieved
	1515	RCS pressure at 910 psig (same as 11 SG pressure) Leak apparently stopped
	1550	Commenced normal cooldown
Oct 3	0640	RHR placed in service to continue cooldown to cold shutdown
	1300	RCS at cold shutdown
Oct 6	1640	Completed draining of RCS
Oct 7	0250	Identified leaking tube

There are several considerations that need to be made during a recovery from an event as this. For the cooldown:

1. Since the leaking steam generator cannot be used for cooling, RCS cooldown will tend to be slower. Also, there will be some delay in cooling the leaking steam generator to the point where entry is possible.

2. With a leak next to the tubesheet, there will be some draining of steam generator water into the RCS. Adequate boron must be injected. In this case, a second boric acid tank was used to raise the boric acid concentration. In 11 steam generator, a sufficiently high boron concentration was measured to ensure no problems with RCS dilution during the cooldown.

3. Since large quantities of 12% boric acid were used for injection via the SI pumps to the cold legs, these lines must be flushed.

D. OPERATIONAL PARAMETER BEHAVIOR - Short Term

The Prairie Island plant computer has the "Post-trip review" option which accumulates plant key parameter data on a continuing basis and saves the data immediately preceding and after a reactor trip. In addition, software has been developed which plots this data. Figures 1 through 7 show the behavior of the following parameters as a function of time:

(1) Pressurizer Level
(2) Pressurizer Pressure
(3) Nuclear Power
(4) Tave
(5) Tc
(6) Delta (Δ) T
(7) Steam Pressure (secondary)

It is worthwhile noting that pressurizer level went off scale before the safety injection occurred due to low pressurizer pressure at 1815 psig. Accident analyses in the past had assumed initiation of the SI signal due to the coincident low pressurizer level (5%) and low pressurizer pressure (1815 psig) signals. In May 1979, the SI actuation scheme had been modified, as a result of Three Mile Island followup evaluations, to a 2-out-of-3 coincidence low pressurizer pressure actuation logic. With either scheme, SI signal initiation would have had to wait until pressure had dropped below 1815 psig. Thus, the safety analysis still bounds the plant response.

Pressure during the most severe portion of the transient was dropping at a rate of about 100 psi/minute. Pressure recovery was rapid once the SI pumps started injecting.

The plots of nuclear power and delta T show the power reduction prior to the trip. The increase in Tave would be expected to accompany the load drop since the rods were at the withdrawal limit.

Tc increased as expected after the load reduction and appeared to be levelling out at about 532F when the trip occurred.

E. OPERATIONAL PARAMETER BEHAVIOR - Long Term

Figure 8 through 17 are recorder tracings showing the long term behavior of the following primary and secondary system parameters in order:

(1) Pressurizer Level and Level Setpoint (0-100%)
(2) Pressurizer Pressure (1700-2500 psig)
(3) RCS Loop Pressure - Loops 11 and 12 (0-3000 psig)
(4) Cold Leg Temperature - Loops 11 and 12 (50-650F)
(5) Hot Leg Temperature - Loops 11 and 12 (50-650F)

(6) Wide Range Steam Generator Level - 11 and 12 (0-100%)
(7) Narrow Range Steam Generator Level - 11 and 12 (0-100%)
(8) Steam Flow/Feedwater Flow - 11 Steam Generator ($0-4.5 \times 10^6$ lb/hr)
(9) Steam Flow/Feedwater Flow - 12 Steam Generator ($0-4.5 \times 10^6$ lb/hr)
(10) Turbine Steam Header Pressure (0-1500 psig)

F. NATURAL CIRCULATION COOLDOWN/TRAINING

After the reactor trip and the safety injection, the reactor coolant pumps were tripped in accordance with I & E Bulletin 79-06C. Cooldown was accomplished using natural circulation until 2128 on 2 October when 12 Reactor Coolant Pump was restarted to allow cooldown using normal procedures. Natural circulation tests and demonstrations have been conducted as part of the preoperational startup testing program and requalification training exercises. In fact most operators have had an opportunity to cooldown the plant using natural circulation. Thus, the operators were aware of what to expect as parameter behavior. Cooldown rates on the order of 50F/hour were obtained with a Delta T of approximately 30F. Cooldown was accomplished by directing steam dump to the condensor during the first phase of the cooldown.

It should also be pointed out that the Prairie Island licensed operator requalification program normally includes simulator training in emergency procedures and accident simulation. Steam generator tube rupture exercises, as well as a variety of other accident conditions, have typically been included in these training programs.

G. RCS LEAK RATE AND MINIMUM RCS WATER INVENTORY CALCULATIONS

Maximum Leak Rate

This calculation is based on pressurizer level vs time from the post trip review data (Table 1 and Figure 1).

Least squares fit of data was performed for those areas of the curve in which pressurizer level was decreasing uniformly, as follows:

(1) 14h 20m 57s to 14h 21m 29s (32 sec.)

Leak rate = -0.163750 %/sec

(2) 14h 22m 25s to 14h 22m 57s (32 sec.)

Leak rate = -0.168749 %/sec

$(\text{Leak rate})_1 = -9.825$ %/min

@ 64.6 g/% for 70° water

= 634.7 gpm

Corrected for water temperature:

Initial cond: 2235 psig $v_f = .0269$

$70^{\circ}F$ $v_f = .01605$

Corrected leak rate = $634.7 \times \frac{.01605}{.0269} = \underline{378.7 \text{ gpm}}$

$(\text{Leak rate})_2 = (-0.168749 \text{ \%/sec}) \left(60 \frac{\text{sec}}{\text{min}}\right) \left(64.6 \frac{\text{g}}{\%}\right) \left(\frac{.01605}{.0269}\right)$

$= \underline{390.3 \text{ gpm}}$

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Minimum Pressurizer Water Inventory

Pressurizer level is calibrated so that 0% should correspond to the lower level tap on the pressurizer for hot pressurizer conditions. For a different set of conditions the lower level tap may correspond to a slightly positive or a slightly negative reading. Figure 1 shows that the lower level tap corresponded to a reading of about -5%, the point at which pressurizer level indication became flat.

By extrapolating the data from the least squares fit through -5%, one can obtain a conservative estimate of the time at which the bottom pressurizer level tap was uncovered:

Time 0 = 14h 22m 25s

From least squares fit:

$$\text{Pzr level} = 9.54\% - 0.16875 \frac{\%}{\text{sec}} \quad \text{(time in seconds)}$$

For Pzr level = -5%,

$$\text{Time} = \frac{(-5\% - 9.54\%)}{-.16875\ \%/\text{sec}}$$

$$= \frac{+14.54\%}{.16875\ \%/\text{sec}}$$

$$= 86 \text{ sec}$$

Time Pzr level reached bottom level tap = 14h 23m 51s

$$\text{Water volume in pressurizer at bottom level tap} = 527\text{g} \times \frac{.01605}{.0269} = 314 \text{ g}$$

From Figure 2, at 14h 24m 33s pressurizer pressure was increasing steadily indicating that RCS water inventory was increasing.

This calculation assumes leak rate continued at maximum (390 gm) from 14h 22m and 25s, when pressurizer level drop was steepest, until 14h 24m and 33s, when pressurizer pressure began increasing. This assumption is conservative in two respects:

(1) Charging pumps were manually started at 1423 and 1424 and SI pumps automatically started at 1424 and 14 sec.

(2) The leak driving force Δp was dropping steadily from 1422 and 25s to 1424 and 33s.

$$\text{Drop in Pzr level below lower pressure tap} = 390 \text{ gpm} \times 42 \text{ sec} \times \frac{\text{min}}{60 \text{ sec}}$$

$$= 273 \text{ gallons}$$

Pzr inventory at low level tap = 314 gallons

Net minimum pzr inventory = 314g - 273g = 41 gallons

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TABLE 1

Time	Pressurizer Level
14h 20m 57s	19.7
14h 21m 05s	18.5
14h 21m 13s	17.1
14h 21m 21s	15.8
14h 21m 29s	14.5
14h 21m 37s	13.2
14h 21m 45s	12.1
14h 21m 53s	11.3
14h 22m 01s	12.1
14h 22m 09s	11.9
14h 22m 17s	11.1
14h 22m 25s	9.7
14h 22m 33s	8.0
14h 22m 41s	6.8
14h 23m 49s	5.5
14h 23m 57s	4.2
14h 23m 05s	3.2
14h 23m 13s	
14h 23m 21s	1.2
14h 23m 29s	
14h 23m 37s	-0.7
14h 23m 45s	-1.6
14h 23m 53s	-2.6
14h 24m 01s	-3.3
Trip	
14h 24m 17s	-4.6
14h 24m 25s	-4.6
14h 24m 33s	-4.6
14h 24m 41s	-4.7
14h 24m 49s	-4.7
14h 24m 57s	-4.8
14h 25m 05s	-4.8
14h 25m 13s	-4.8
14h 25m 21s	-5.0

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H. RADIOACTIVE RELEASES

The plant health physics staff monitored the plant environment for offsite release and determined activity levels of radioactive liquids and gases contained by plant systems or released to the environment.

Airborne Activity

Gas releases were made through the following paths:

(1) Air ejector discharge
(2) Turbine driven auxiliary feed pump exhaust
(3) Atmospheric steam dump
(4) Gland steam exhaust

The following is a summary of the releases made via those paths

Periodic grab samples were taken on the air ejector exhaust in order to accurately assess the activity released via this path. The air ejector was used during the period 1414, 2 October 1979 through 0730, 3 October, 1979. Even though the 11 steam generator was isolated at 1441, the health physicists deemed it prudent to monitor the exhaust until the unit was secured. The following table summarizes the activity released during the period.

TABLE 2

Gaseous Releases via the Air Ejector

Nuclide	Activity (C_i)
Xe^{133}	21.9
Xe^{135}	4.63
Ar^{41}	2.00 E-05
Kr^{85m}	0.034
Kr^{87}	0.446
H^3	1.94 E-05
Total Activity	27.01 C_i

The turbine driven auxiliary feed pump was operated for approximately 24 minutes (until after SI was reset). Based on the 1715 steam generator activity data and assuming full flow with the auxiliary feed pump (a conservative assumption), the following is a summary of the radioactive releases via this path:

TABLE 3

Gaseous and Iodine Releases via the TD Aux Feed Pump

Nuclide	Activity (μc)
Xe^{133}	3.07 E+5
Xe^{135}	8.73 E+4
Kr^{85m}	2.46 E+4
Kr^{87m}	2.20 E+4
Ar^{41}	3.92 E+4
I^{131}	4.81 E-1
I^{133}	3.06 E-1

One of the 2 atmospheric steam dump valves off loop A opened for 3 seconds after the reactor trip. This time is fairly typical based on previous operating experience. These valves normally take about 3 seconds to stroke full open. In order to determine the possible release via this path, it was assumed that full flow passed for 3 seconds and activities were backcalculated from the 1715 sample (as for the TD auxiliary feed pump evaluation). The releases were as follows:

TABLE 4

Gaseous and Iodine Releases via the Steam Dump

Nuclide	Activity (μc)
I^{131}	0.54
I^{133}	0.35
Xe^{133}	3.42 E+4
Xe^{135}	9.72 E+3
Kr^{85m}	2.74 E+3
Kr^{87}	2.45 E+3
Ar^{41}	4.37 E+3

No estimate of the release via the gland steam exhaust is available at this time. Release by this path is expected to be less than that via the air ejector path. Further investigations will be made in this area.

Liquid Activity

The air ejector condensor drains to the turbine building sump. Liquid samples were taken during the period that releases were made from the turbine building sump. The table below summarizes the releases made during the period 2 October 1979 through 4 October 1979.

TABLE 5

Date	Nuclide	Activity Released (μc)
2 Oct	Xe^{133}	1.23 E+3
	Xe^{135}	7.56 E+3
3 Oct	Xe^{133}	1.08 E+4
	Xe^{135}	2.51 E+3
4 Oct	Xe^{133}	1.13 E+3

Total Activity Released = 2.32 E+4 μc

Steam generator blowdown was being directed to the condensor prior to the tube failure, thus this reduced one possible path for liquid release to the environment. The circulating water system was operating in the recycle mode where only 150 cfs may be returned to the Mississippi River. This tended to spread out the releases from the turbine building sump to the river over a longer period. There was no detectable iodine in the liquid samples during this period.

I. OFFSITE TLD MEASUREMENTS

TLD's had been placed in four locations near the Prairie Island facility on 2 October 1979 (see table below for exact details) as the fourth quarterly TLD's. These were replaced on 3 October 1979 because of the incident. These TLD's were shipped to and developed by Hazelton Environmental Sciences Corporation, of Northbrook, Illinois. These devices had a higher uncertainty because of higher in-transit exposure compared to those experienced in the field. Table 6 summarizes the TLD location, exposure period, duration and total exposure as reported by Hazelton Services.

TABLE 6

TLD Gamma Radiation Exposure

Location	Exposure Period (Times)	Duration of Exposure (Hours)	Total Exposure (mrem)
PI-1 Prescott	10-2; 1100 to 10-3; 1500	28	0.18 ± 0.42

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TLD Gamma Radiation Exposure

Location	Exposure Period (Times)	Duration of Exposure (Hours)	Total Exposure (mrem)
PI-2 Ellsworth	10-2; 1030 to 10-3; 1535	29	0.33 $\pm$ 0.40
PI-3 NW Sector	10-2; 1315 to 10-3; 1615	27	0.27 $\pm$ 0.42
PI-4 Lock&Dam #3	10-2; 1330 to 10-3; 1620	27	0.28 $\pm$ 0.39

These measurements show the low dose that could have been received and these should have been low due to the low level release that occurred.

J. RCS IODINE BEHAVIOR

Over 90 RCS I^{131} samples were measured in the 5 1/2 days after the event because of the interest in the spiking phenomenon and the transfer of coolant from the RCS to the secondary with subsequent possible release of activity to the environment. Figure 18 shows the I^{131} activity behavior during the period 1515, 2 October 1979 through 2200, 7 October 1979. Also indicated on the plot is the I^{131} level measured at 0730, 2 October, and shown as the pre-trip level. The Iodine -131 activity leveled out at approximately 8.5×10^{-3} μc/ml because the purification system ion exchangers had been valved out after the trip to prevent reduction in the RCS boron concentration.

K. STEAM GENERATOR INSPECTION/CORRECTIVE ACTIONS

An inspection program of the steam generator tubes was conducted with the following objectives:

(1) to identify the ruptured tube
(2) to obtain information on the possible cause of the tube rupture
(3) to detect any further tube degradation in the steam generator, and
(4) to determine the general condition of the steam generator tubing.

The evaluation of the break and identification of the exact failed tube was accomplished by draining water from the secondary side of the steam generator into the RCS through the opening of the leaking tube. Once the water on the secondary side stopped draining, the break elevation was determined. Then by slowly adding water to the secondary side and visually inspecting the tube sheet from the primary side through the manways, the specific tube was identified.

Since the leaking tube (Row 4, Column 1, Inlet side) was located in the outer periphery of the tube bundle and the break was just above the tube sheet within the flow lane. foreign object damage was suspected. Therefore, the eddy current inspection shown in Figures 19 and 20 for 11 steam

generator and Figure 21 for 12 steam generator) was concentrated in the outer periphery tubes. The inspection program was conducted in accordance with Technical Specifications, Section 4.12. The results of the eddy current examinations revealed that the Row 3, Column 1 tube (adjacent to the failed tube) had indication of a 65% reduction in wall thickness. The Row 2, Column 1 tube (next tube) had a possible indication of <20% reduction in wall thickness. All of these indications were at approximately the same elevation.

A complete visual examination of the outer peripheral area of the tube bundles and the flow lanes for both steam generators revealed no other signs of foreign objects. In addition, the eddy current examinations conducted for both steam generators revealed no other tubes with wear or degradation.

With the aid of mirrors and fiber optics, a visual examination of the three degraded tubes verified the eddy current results and revealed that the break resembled a classical overpressure burst (running approximately 1 1/2" in the longitudinal direction of the tube with an opening width of approximately 1/2"). The other two tubes (Row 3, Column 1 and Row 2, Column 1) showed signs of wear. All wear marks were on the outer peripheral side of the tubes. These patterns were documented by photographs and are depicted in Figure 22.

During this time, a coil spring, later measured to be 8.5" long, 1.25" diameter, and 3/32 gauge was found to be lying on the tube sheet adjacent to the defective tubes. One end of the spring was lodged under the tube lane blocking device and the other end was free to move. Figure 23 is an overhead view showing the location of the spring, tube lane blocking device, and the peripheral tubes. Figure 24 is a side view, and Figure 25 is a front view. A definite wear pattern on the tube sheet indicated that the spring had moved during operation. Later, a second spring, identical to the first, was found on the cold leg side. It was located just opposite the first spring in a similar condition with one end lodged under the tube land blocking device and the other end extending out onto the tube sheet. In addition, part of an aviation hose clamp was found next to this spring on the cold leg side. A close visual examination of the spring on the cold leg side, the tubes and the tube sheet surface revealed no signs of spring movement, tube damage or wear. This was confirmed by eddy current examination of all eight tubes in Column 1 in close proximity to the second spring.

Once these objects were removed from the steam generator it was apparent that the spring and piece of hose clamp from the cold leg side were encrusted with oxides indicating no active movement while the coils of the spring from the hot leg side had definite signs of wear.

These springs have been shipped to Westinghouse for further examination. The springs and clamp appear to have been part of sludge lancing equipment used in one of the previous outages. Table 7 summarizes the work history on the Unit 1 steam generators. It appears that this spring was dropped into the steam generator prior to installation of the tube lane blocking device. Investigations in this area are continuing.

Three courses of corrective action were identified based on the following facts:

(1) the pattern of tube wear
(2) the location of tube wear relative to the spring location
(3) the wear pattern of the spring on the tube sheet
(4) the signs of wear on the spring wire
(5) no other tubes that were inspected other than the three previously discussed had any signs of wear or tube degradation
(6) No other foreign objects were found.

It has been concluded that the tube break was the result of reduction of wall thickness by the wearing action of the spring against the tube.

The three courses of corrective actions identified were - (a) plug the two defective tubes and several adjacent tubes, (b) remove a section of the defective Row 4 tube and plug the two defective tubes, or (c) stabilize the stabilize the defective Row 4 tube from the primary side and plug the two defective tubes. Discussions among NSP, Westinghouse, and NRC staff revealed that option (a) should be selected for several reasons -

(1) in accordance with ALARA, the occupational exposure would be least,
(2) uncertainties in the design concept of tube stabilization, and
(3) minimize effects of possible instability of the defective Row 4 tube.

In addition to the failed tube, and the tube with 65% wall reduction, the remaining four adjacent tubes to the failed tube were plugged. This action was taken to eliminate the remote possibility of the failed tube breaking further and damaging the adjacent tubes. A secondary side pressure test is being conducted to assure leak tightness of the plugs.

TABLE 7

UNIT #1 STEAM GENERATOR HISTORY

OUTAGE DATE	WORK PERFORMED	EDDY CURRENT	SLUDGE LANCING
12/17/73	PERFORATED PLATES	NONE	NO
09/05/74	NONE	BOTH S.G.s	BOTH S.G.s
04/25/75	NONE	BOTH S.G.s	BOTH S.G.s
03/04/76	MODIFIED S.G.ORIFICE, DECKS, F.W. RING & BLOWDOWN LANES	BOTH S.G.s	BOTH S.G.s
04/17/77	NONE	BOTH S.G.s	BOTH S.G.s
03/26/78	NONE	S.G. #12	BOTH S.G.s
04/06/79	NONE	NONE	BOTH S.G.s

L. RECOVERY

The following schedule is planned for return to power depending upon activity cleanup in the secondary system:

Date	Event
Oct 17	Fill and vent RCS
Oct 19	Heatup the RCS
Oct 21	Reactor critical
Oct 22	Unit at 50% power

M. PLANNED ACTIONS

During the next refueling outage, the plant staff will inspect the area of the failed tube for anomalous behavior of the plugged tubes.

N. COMPARISON OF FSAR RESULTS VS ACTUAL BREAK RESULTS

The Prairie Island FSAR Section 14.2.4 addresses a steam generator tube rupture. The table below summarizes differences between the FSAR calculations and the October 2 break results:

TABLE 8

Comparison of FSAR and Actual Break Results

Item	FSAR	Prairie Island Tube Break
Leak rate, gpm	~616	~390
Percent defective fuel, %	1.0	0.01
Previous leak rate prior to break, gpm	5.0	0.0
Lbs., steam transfer 30 minutes	120,000	~5,000*
Radioactivity released, C_i		
Xe^{133} equivalent	21,700	~30 (actual Xe^{133})
I^{131}	209	~1.0E-6 (actual)

*NOTE - Steam released from operation of the turbine driven auxiliary feedpump and steam dump to atmosphere actuation.

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The FSAR assumed specific radionuclide concentrations in the RCS coolant as shown in Table 9 which compares selected radio nuclides to the actual concentrations in the RCS coolant as measured at 0730 on 2 October 1979. It should be noted that all actual concentrations were well below the postulated FSAR concentrations, thus assuring that the radioactivity levels released during the event were bounded by the FSAR analysis.

TABLE 9

Comparison of FSAR and Actual RCS Activities (μc/ml)

Noble Gases	FSAR [1]	Measured Activity [2]
Kr^{85}	1.11	-----
Kr^{85m}	1.46	1.19×10^{-2}
Kr^{87}	0.87	1.60×10^{-2}
Kr^{88}	2.58	------
Xe^{133}	1.74×10^{2}	3.35×10^{-1}
Xe^{133m}	1.97	5.63×10^{-3}
Xe^{135}	4.95	8.32×10^{-2}
Xe^{135m}	0.14	--------
Xe^{138}	0.36	--------
Ar^{41}	----	1.18×10^{-3}
Corrosion Products/Activation Products		
Mn^{54}	4.2×10^{-3}	1.19×10^{-3}
Co^{58}	8.1×10^{-3}	3.18×10^{-4}
Na^{24}	-------	3.83×10^{-3}
Non Volatile Fission Products		
I^{131}	1.55	2.15×10^{-2}
I^{133}	2.55	1.08×10^{-2}

Comparison of FSAR and Actual RCS Activities ($\frac{\mu c}{ml}$)

Noble Gases	FSAR [1]	Measured Activity [2]
I^{135}	1.4	7.0×10^{-3}
Cs^{136}	0.33	6.7×10^{-4}
Cs^{137}	0.43	1.73×10^{-3}
Cs^{139}	--	2.45×10^{-4}
Tc^{99m}	--	1.40×10^{-3}
Mo^{99}	2.11	8.47×10^{-4}
Y^{88}	--	1.78×10^{-3}

NOTES

1. FSAR Appendix D4
2. Sample taken 2 October 1979, 0730

O. RECOMMENDATIONS

A review of the event has resulted in the following recommendations and comments --

(1) A note of caution should be added to the steam generator tube rupture procedure to have the operator stop the turbine-driven auxiliary feed pump as soon as possible and to shut the steam supply valve from the affected steam generator. This was done even though this caution had not been in the procedure.

(2) Add a note of emphasis to the operator to isolate the leaking steam generator as soon as possible and to keep in mind that the MSIV bypass can be used to protect the steam generator from overpressure. Also, reducing the RCS pressure quickly, while maintaining adequate RCS subcooling, (which was done during this event) will help prevent overpressure of the secondary side.

(3) Consider operation of the reactor coolant pumps during a steam generator tube break. This would allow use of the spray valves in the depressurization process, which could minimize the chance of blowing the pressurizer relief tank rupture disc. It should be pointed out that even though the disc failed, there was little discharge to the containment.

(4) The industry should consider the problems associated with a tube break recovery, in particular --

(a) increasing pressure indicates level has probably reached its lowest point and that level is recovering (even if off-scale low), and

(b) bringing pressure up in the pressurizer to greater than 2000 psig leads to increasing flow OUT of the break (thus slower recovery) and decreasing makeup flow from the SI pumps (due to pump-head curve characteristics)

(5) Evaluate the feasibility of not isolating instrument air to the containment, since the PORV's are used to reduce RCS pressure in this event. Under current logic and procedures, containment isolation must be reset to repressurize the PORV accumulators.

(6) Upgrade procedures for control of material into and out of the steam generator and other enclosed spaces.

P. SUMMARY

This 14-day report has attempted to completely address all areas of interest to the NRC. Additional reports will be submitted, as appropriate.

1203 154

L0480A

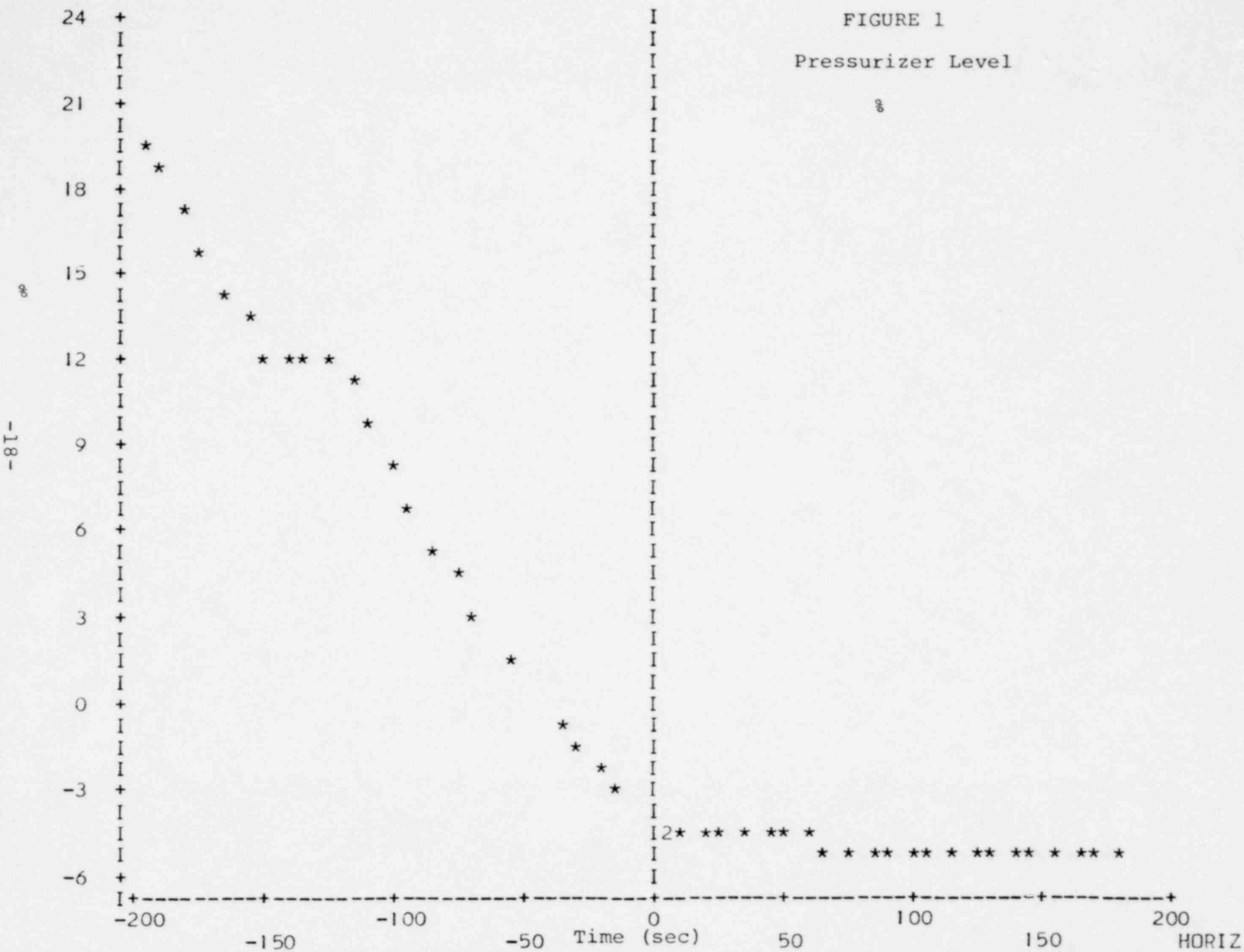


FIGURE 1

Pressurizer Level

%

1203 155

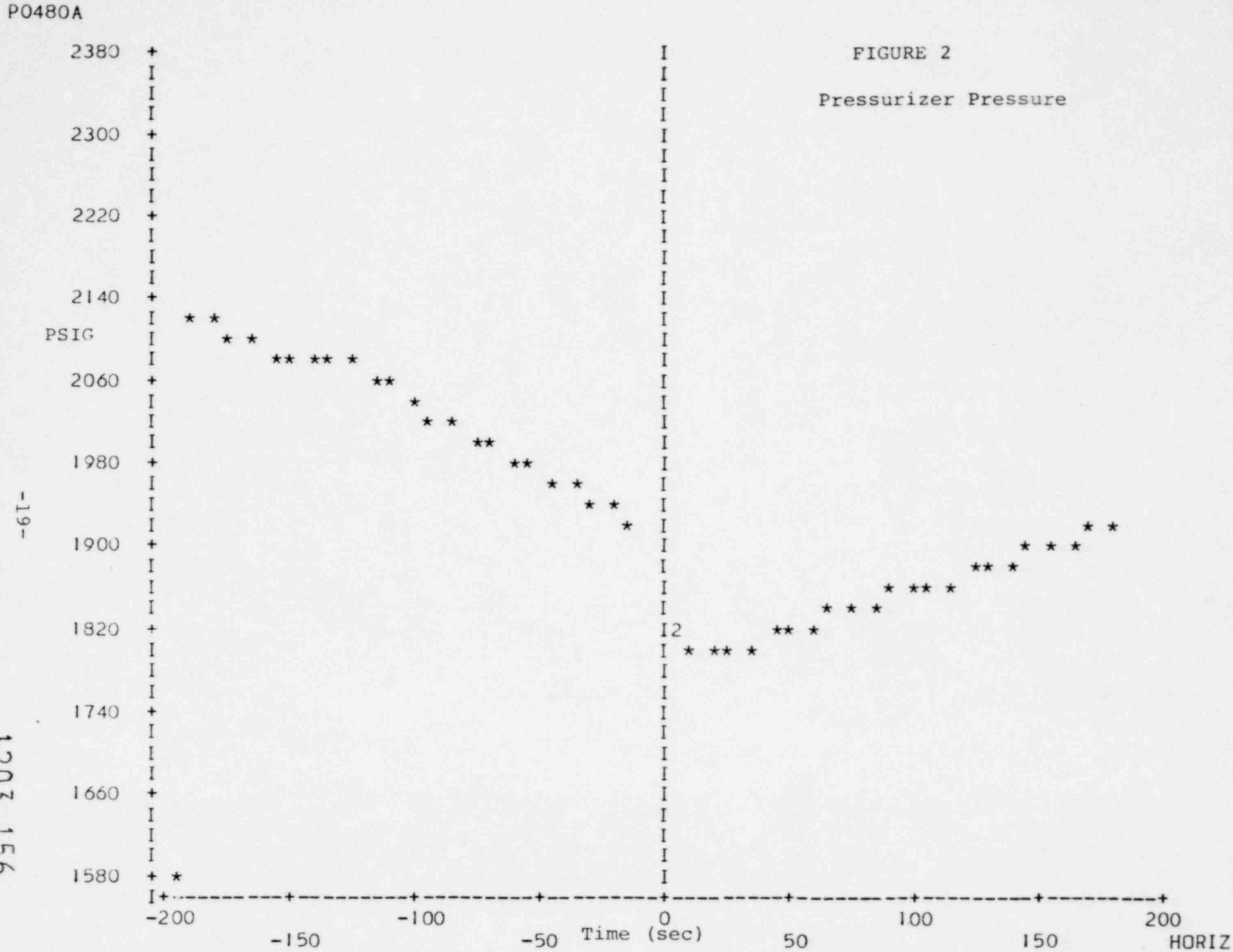


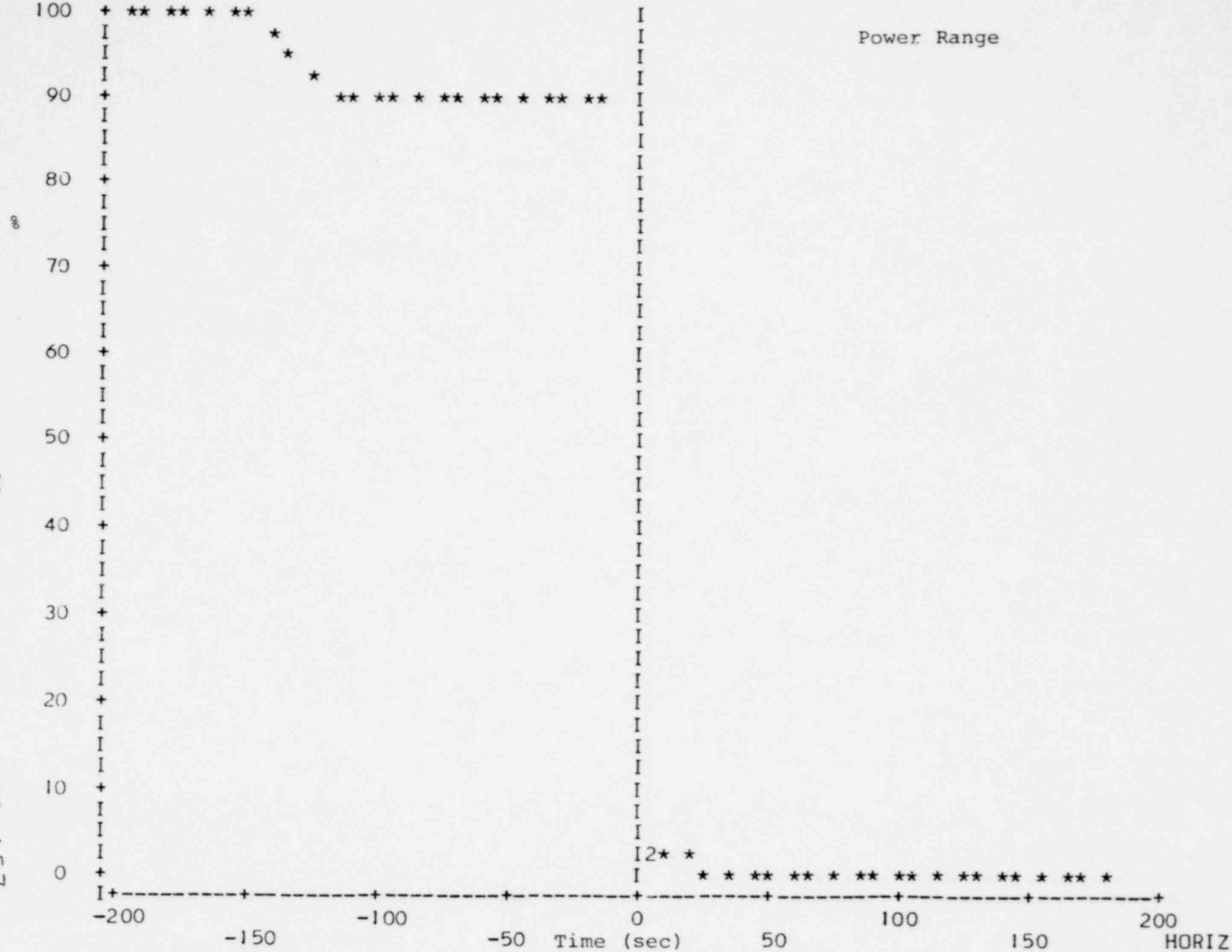
FIGURE 2

Pressurizer Pressure

N0052A

FIGURE 3

Power Range

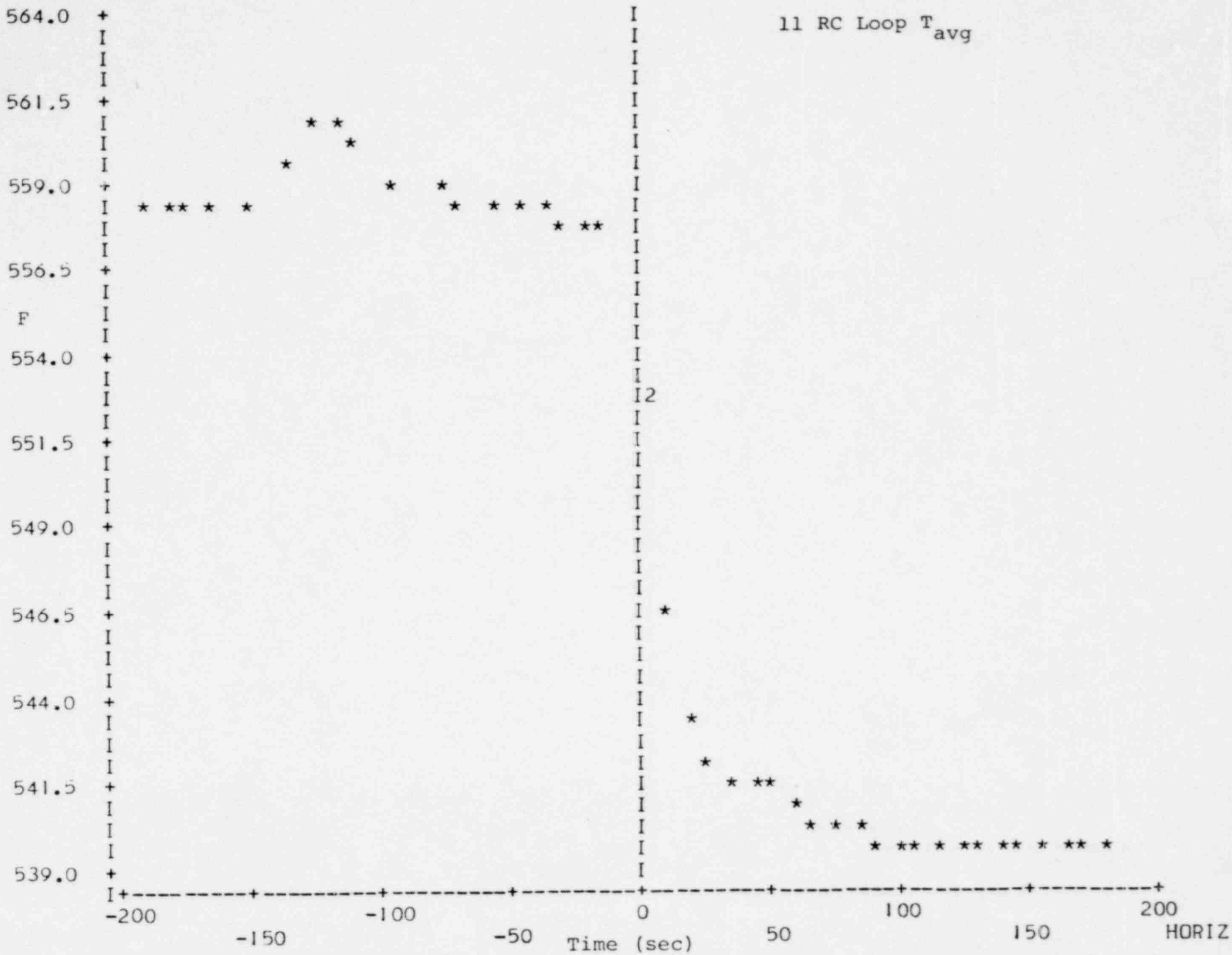


1203 157

T0401A

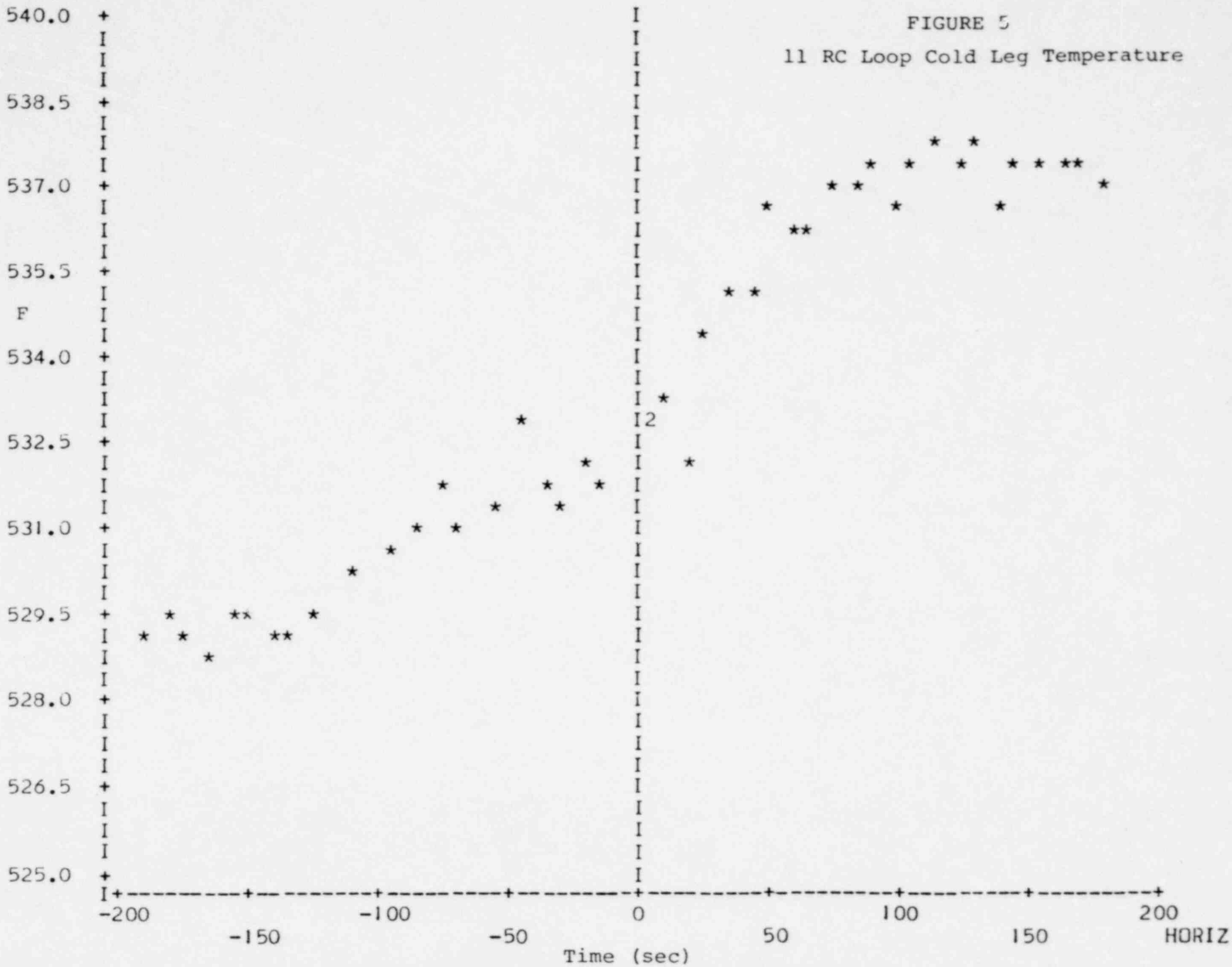
FIGURE 4

11 RC Loop T_{avg}



1203 158

T0406A



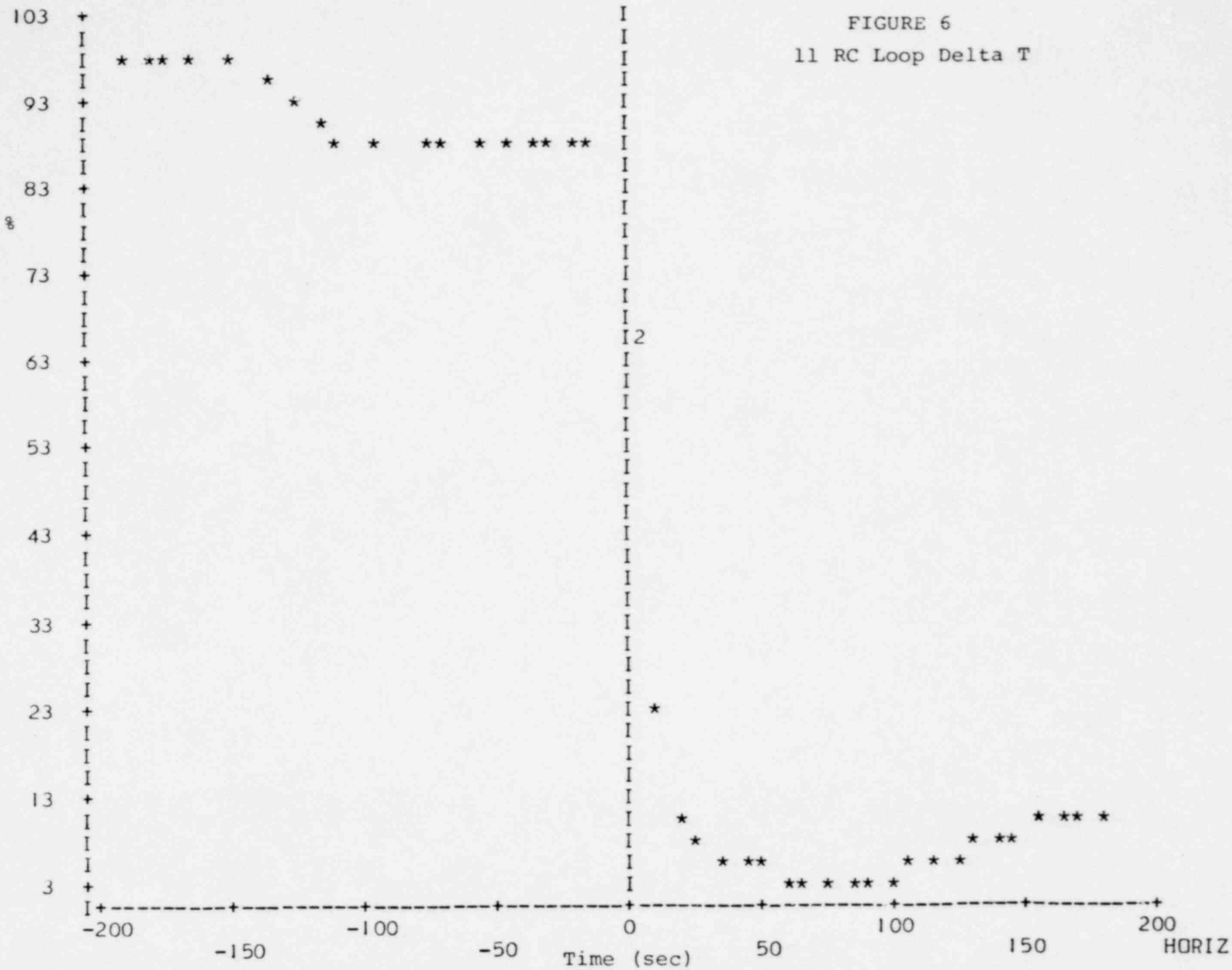
-22-

1203 159

T0403A

FIGURE 6

11 RC Loop Delta T

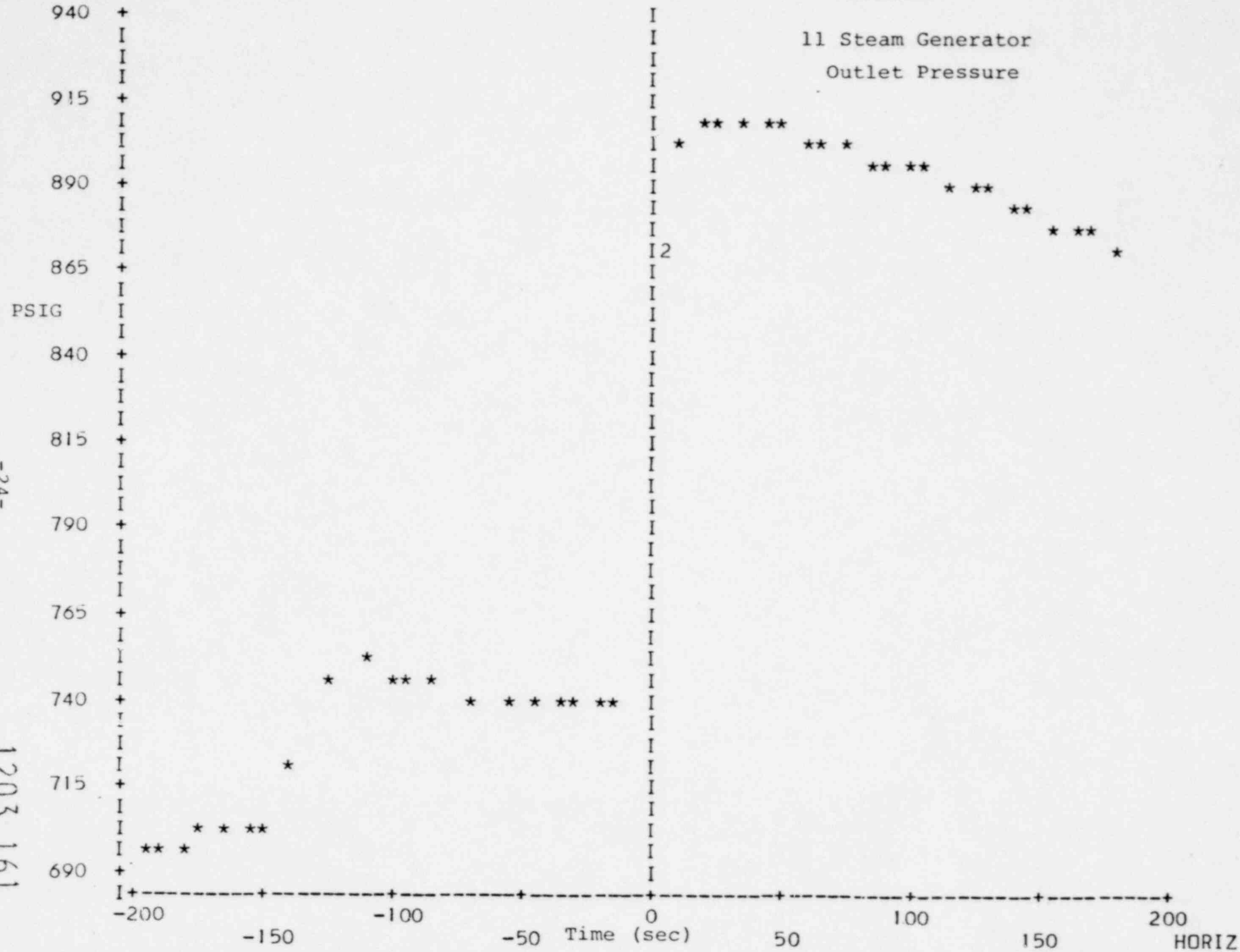


1203 160

P0401A

FIGURE 7

11 Steam Generator Outlet Pressure



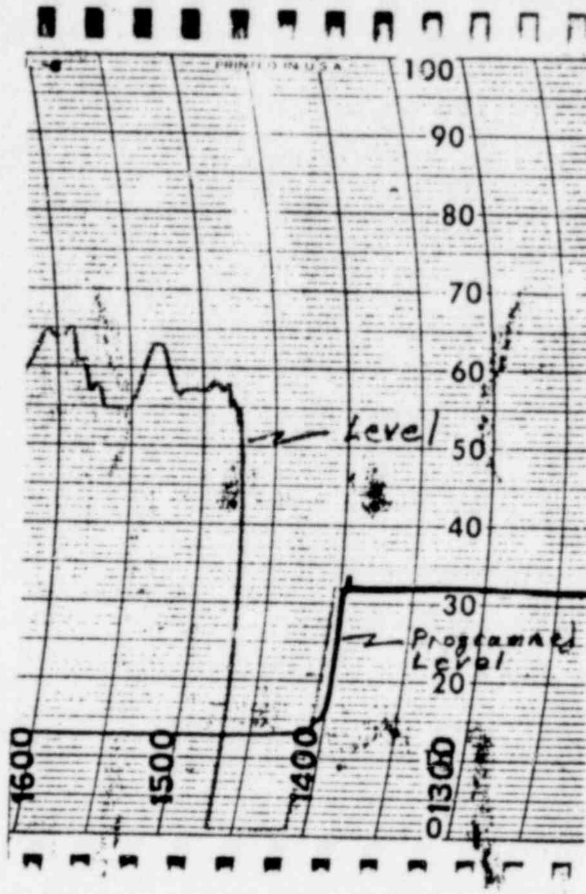


FIGURE 8

Pressurizer level
& level setpoint

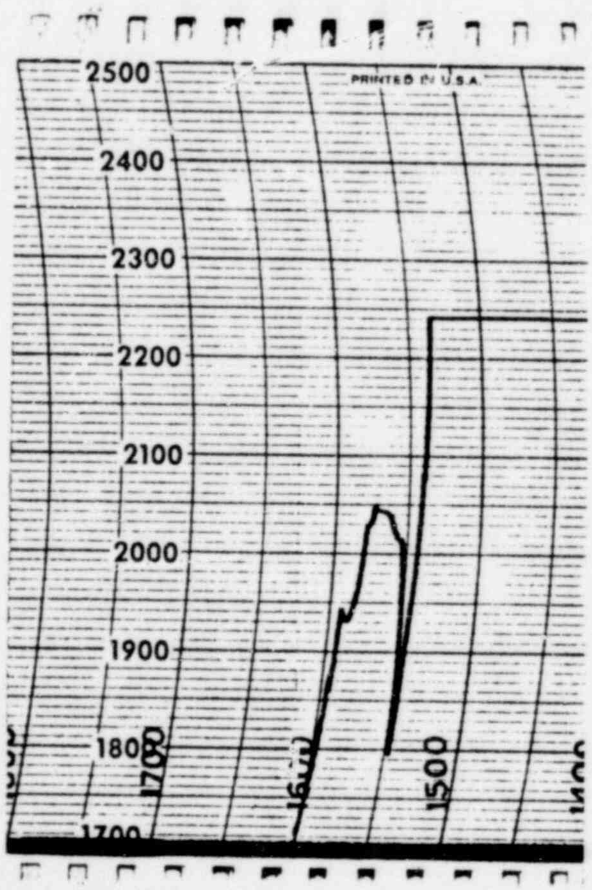


FIGURE 9

Pressurizer
Pressure

1203 162

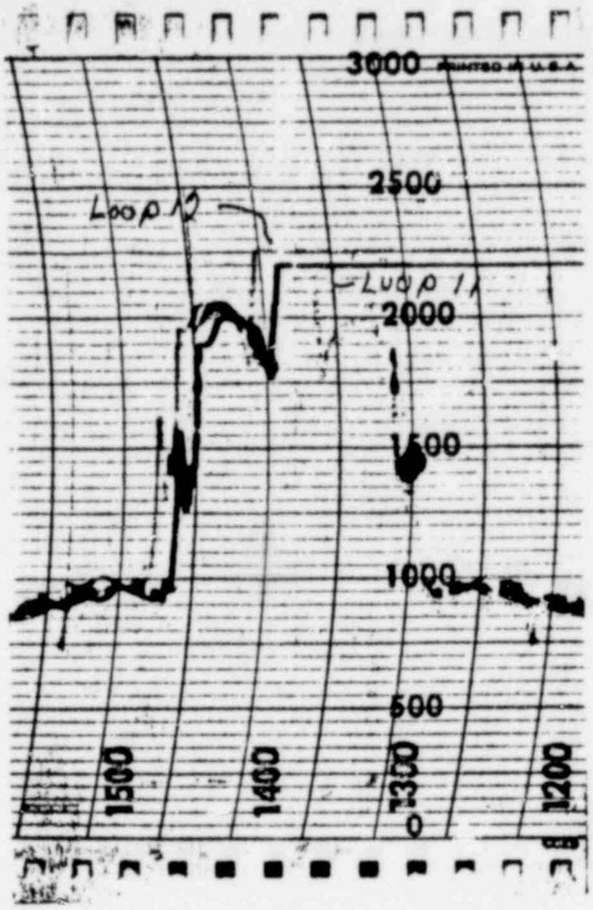


FIGURE 10

RCS Loop Pressure

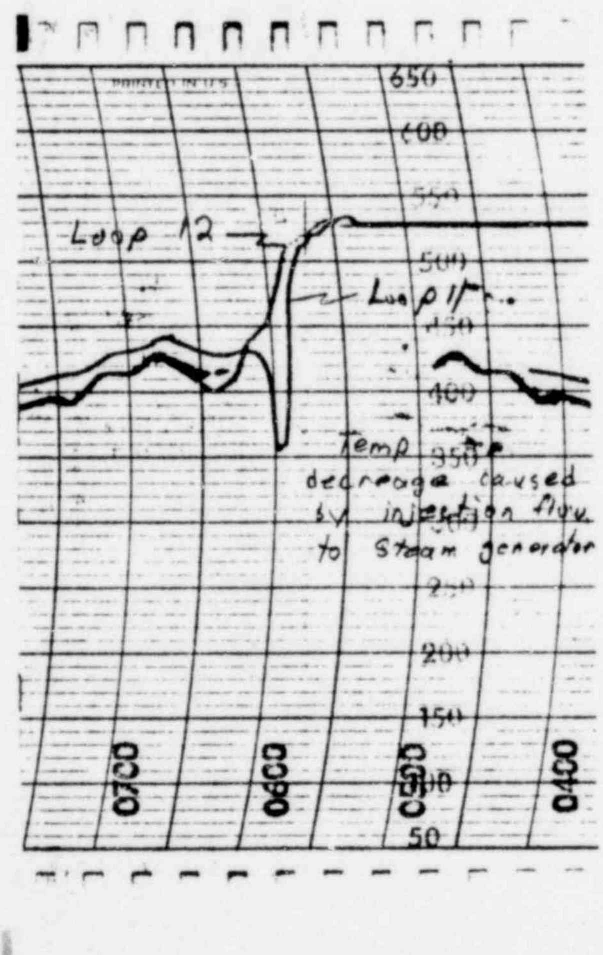


FIGURE 11

Temperature -
11 & 12 Cold Legs

1203 163

POOR ORIGINAL

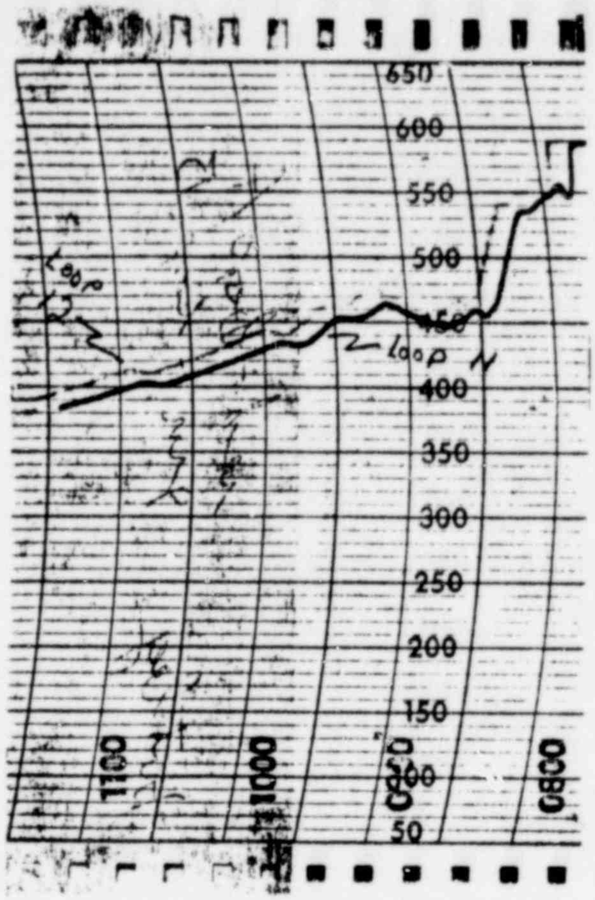


FIGURE 12

Temperature -

11 & 12 Hot Legs

POOR ORIGINAL

1203 164

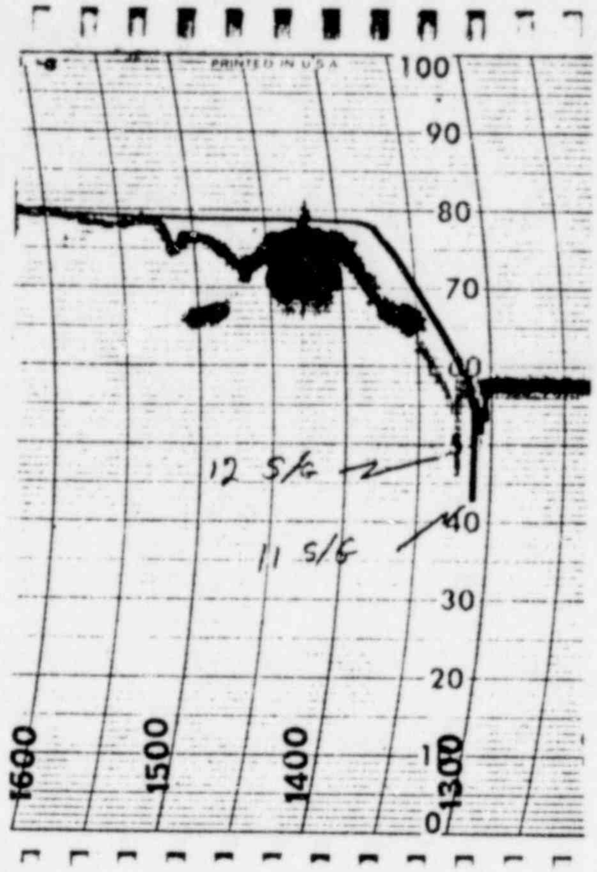


FIGURE 13

Steam Generator Wide Range Level - 11 & 12 S/G's

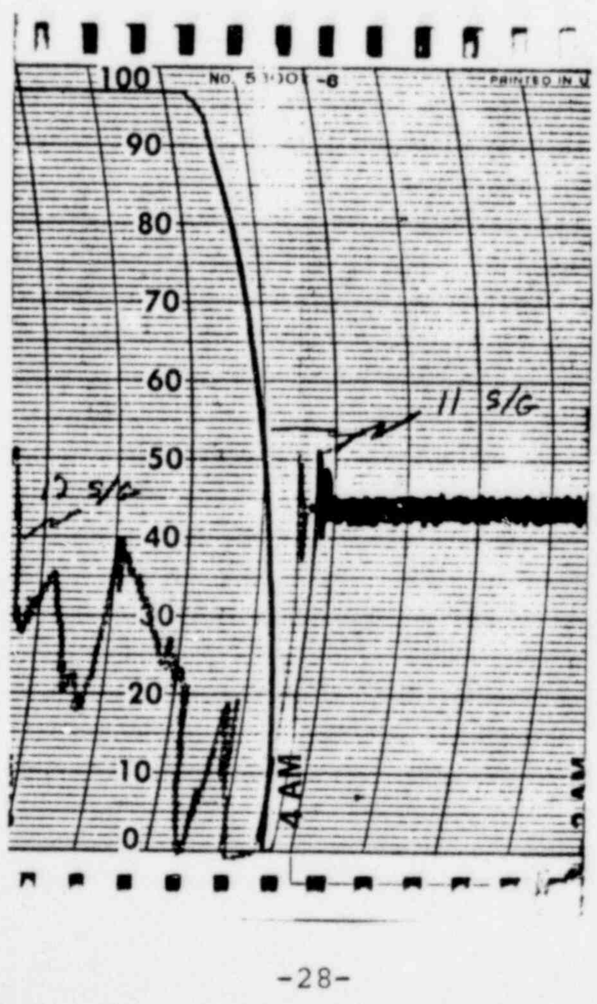


FIGURE 14

Steam Generator Narrow Range Level - 11 & 12 S/G's

POOR ORIGINAL

1203 165

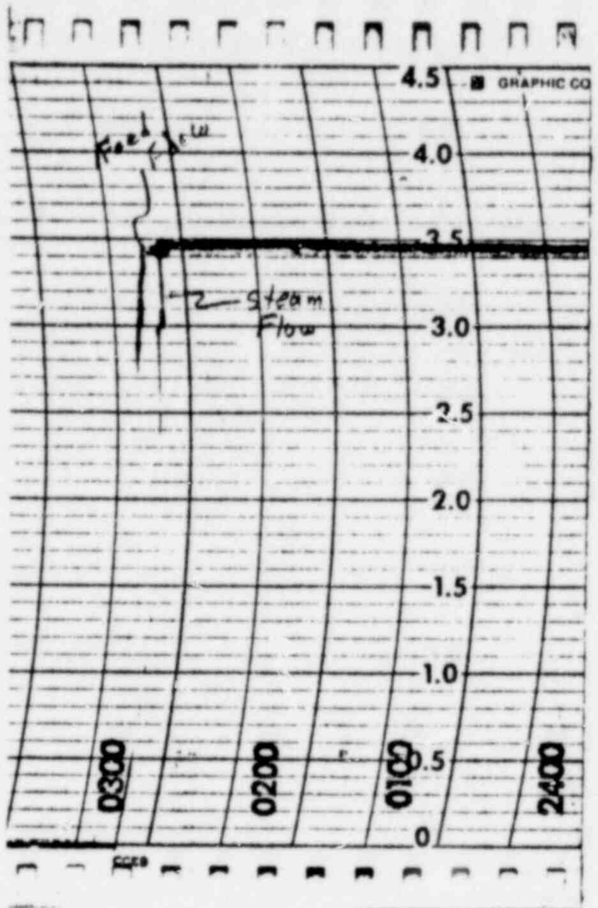


FIGURE 15

11 Steam Generator Steam Flow & Feedwater Flow

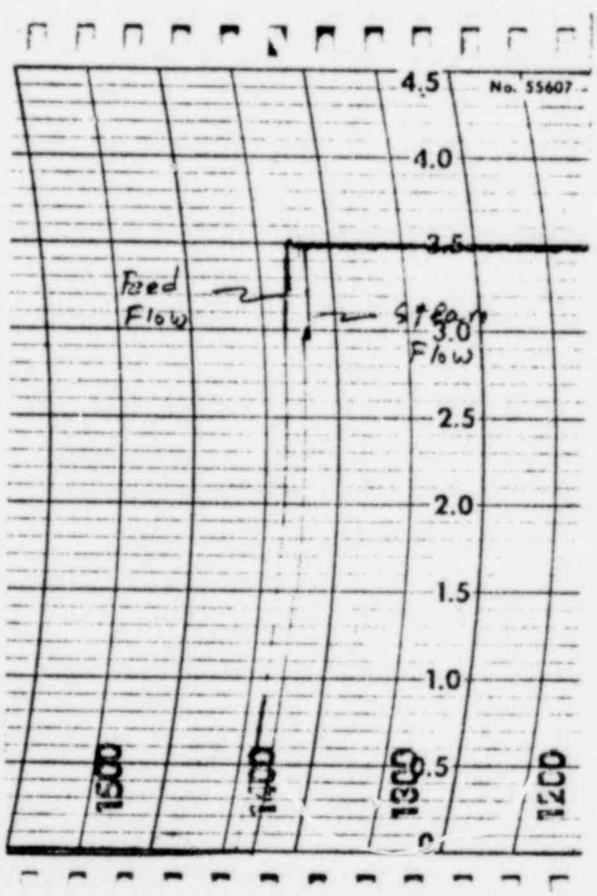


FIGURE 16

12 Steam Generator Steam Flow & Feedwater Flow

POOR ORIGINAL

1203 166

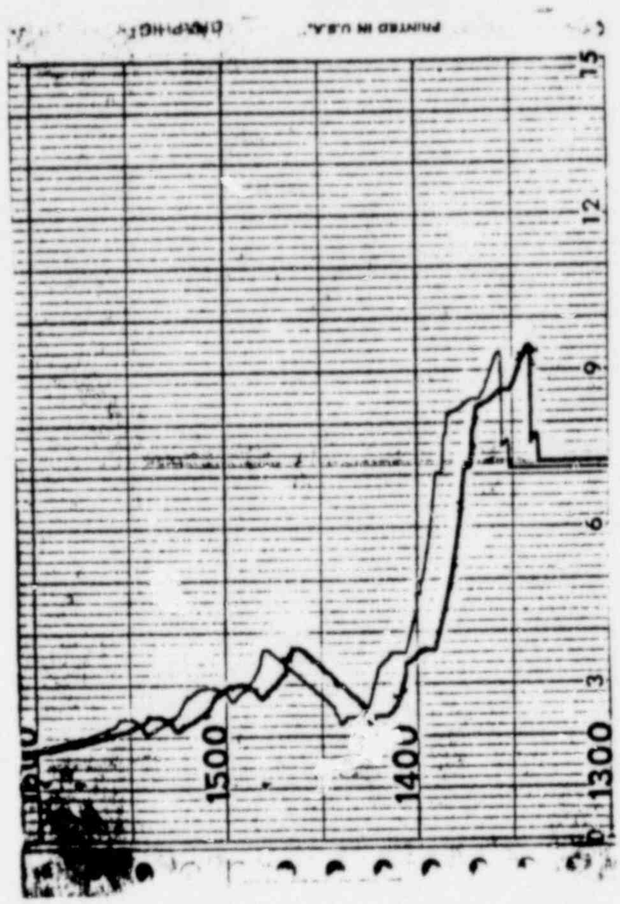


FIGURE 17

Turbine Steam Header Pressure

POOR ORIGINAL

1203 167

POOR ORIGINAL

FIGURE 18

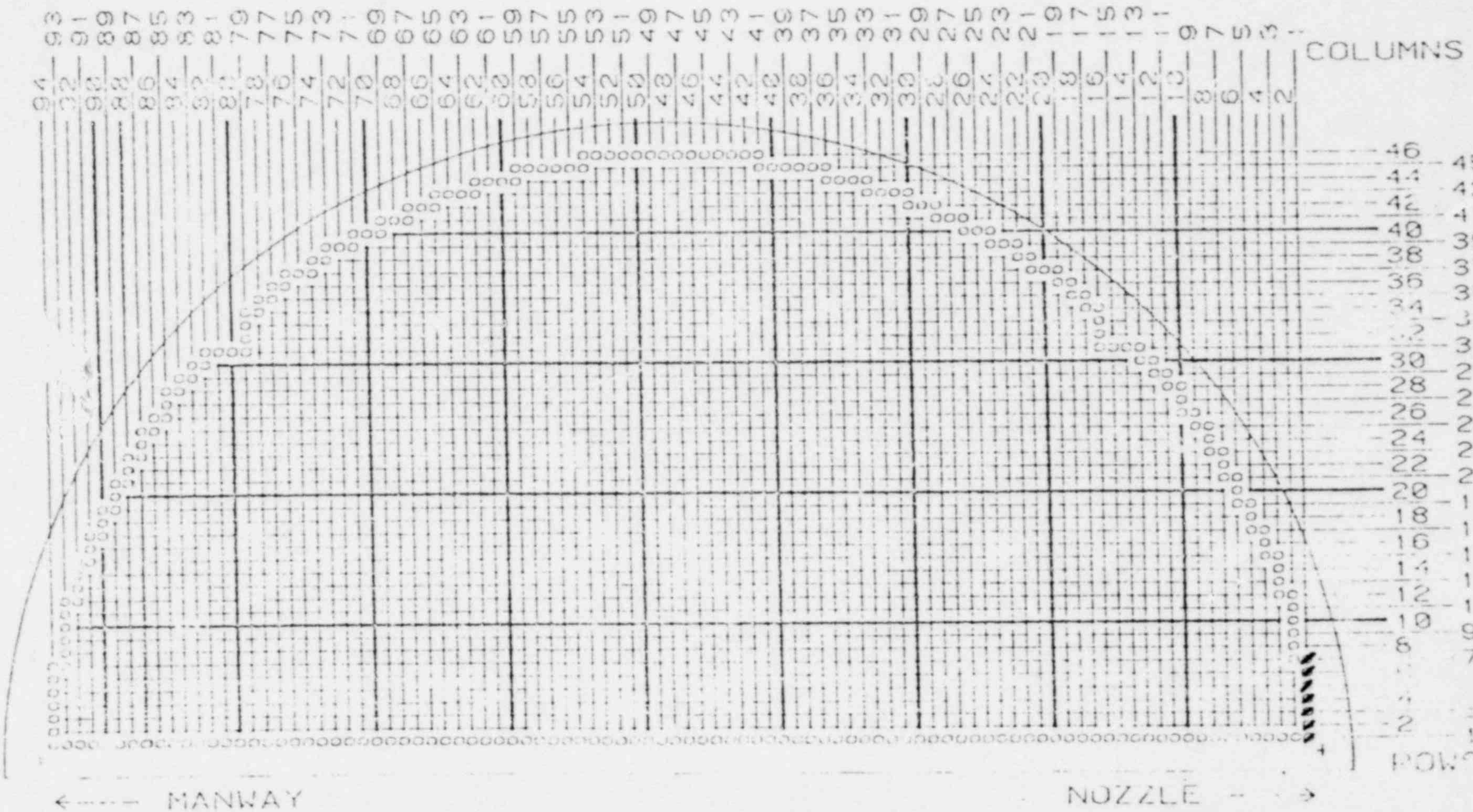
INSPECTION PROGRAM

1. ● COMPLETE U-BEND
2. X 7th TUBE SUPPORT PLATE
3. / NOT COMPLETELY INSPECTED
4. □ TEMPLET PLUG

FIGURE 19

#11 S/G OUTLET

SERIES 51



NOTE: COLUMN ONE INSPECTED TO 1ST SUPPORT PLATE

1203 169

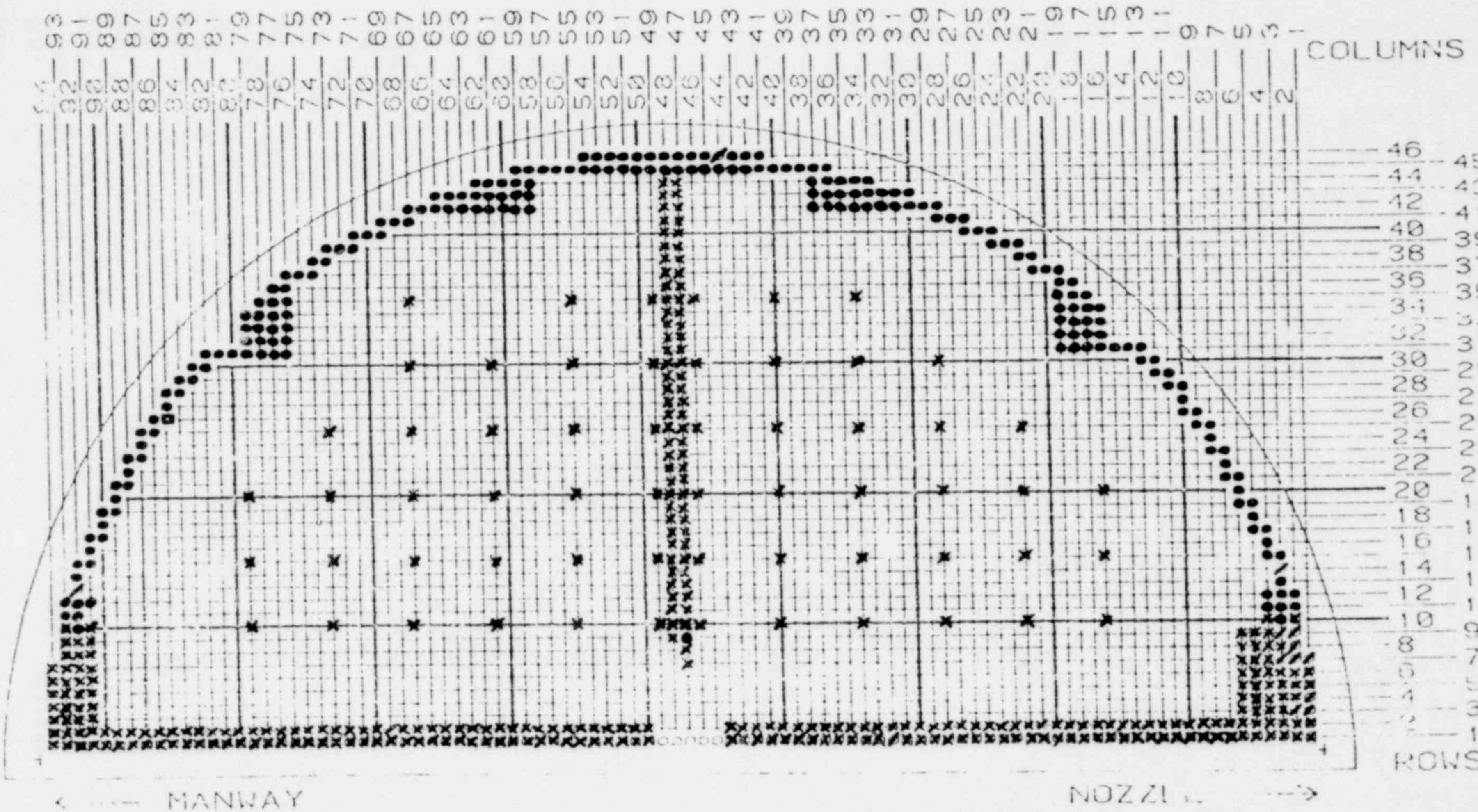
INSPECTION PROGRAM

1. ● COMPLETE U-BEND
2. X 7th TUBE SUPPORT PLATE
3. / NOT COMPLETELY INSPECTED
4. □ TEMPLET PLUG

FIGURE 20

#11 S/G INLET

SERIES 51



NOTE: ALL THE TUBES IN ROW ONE WITH AN "X" WERE ALSO 100K HZ INSPECTED OVER U-BEND

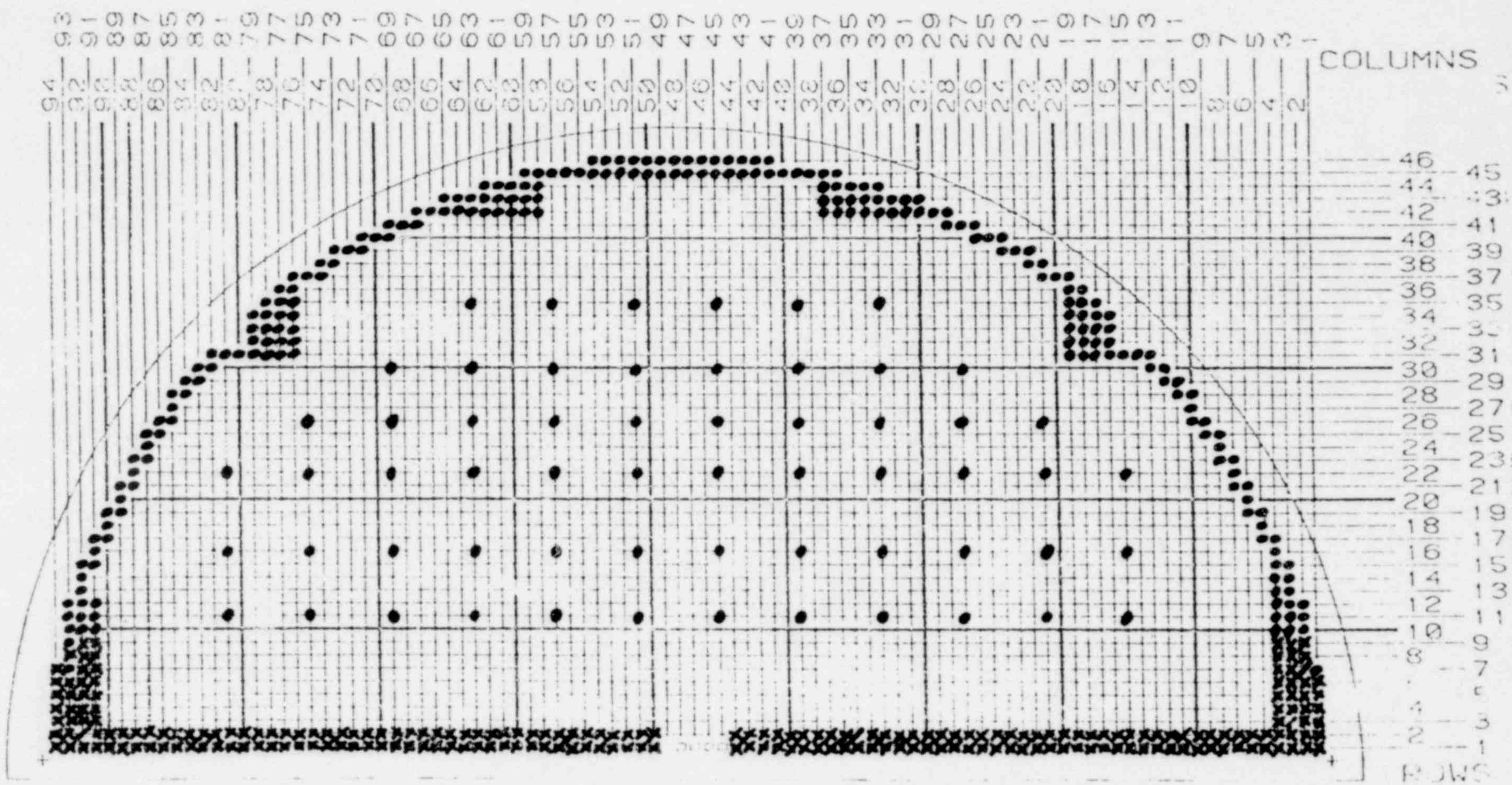
INSPECTION PROGRAM

1. ● COMPLETE U-BEND
2. X 7th TUBE SUPPORT PLATE
3. / NOT COMPLETELY INSPECTED
4. □ TEMPLET PLUG

FIGURE 21

STEAM GENERATOR #12

SERIES 51



NOTE: IN ADDITION ALL ROW 1, EXCEPT COLUMNS 45 THRU 48, WERE EXAMINED IN THE TIGHT RADIUS U-BEND (100 KHZ ABSOLUTE)

1203 171

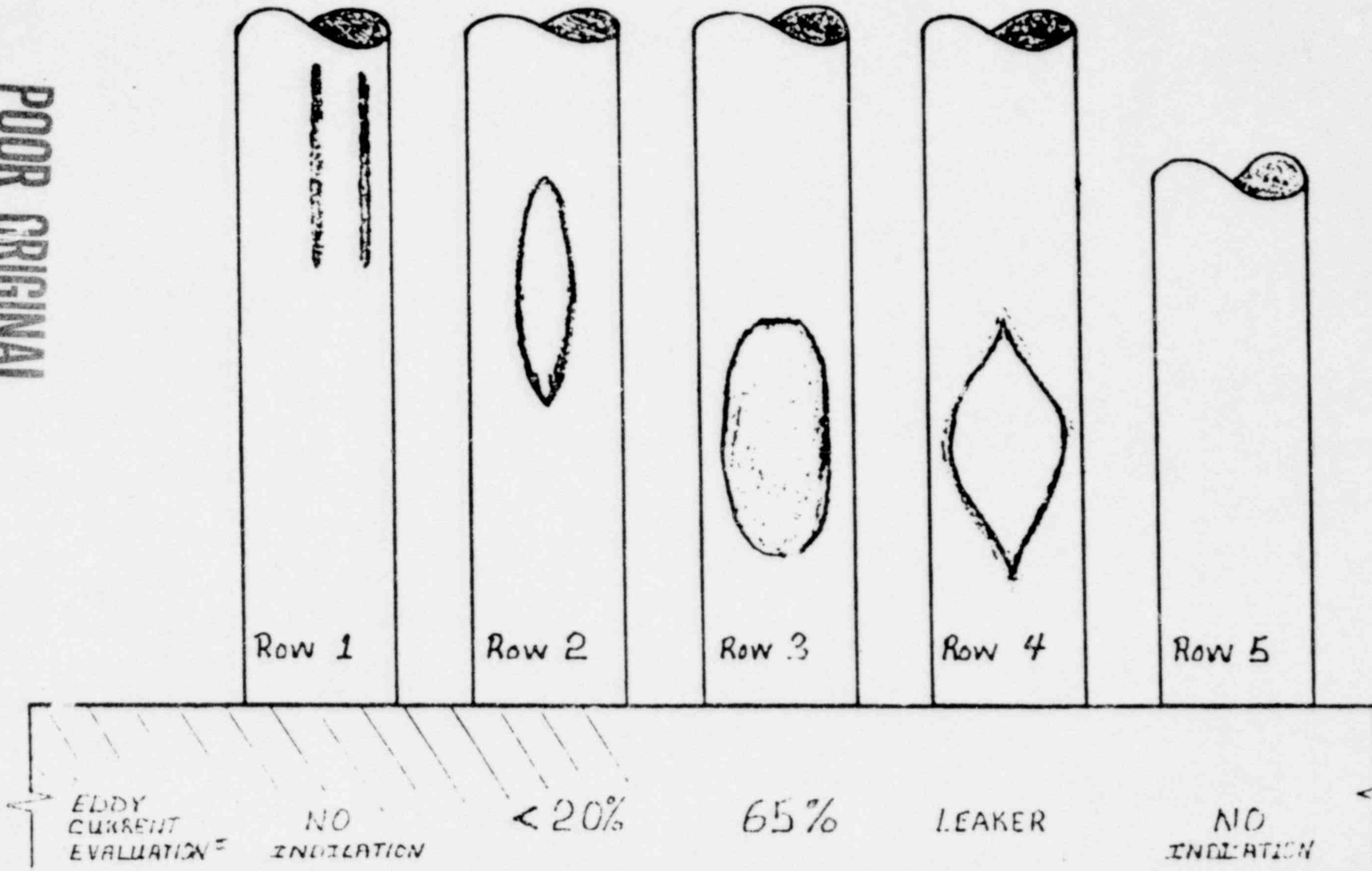
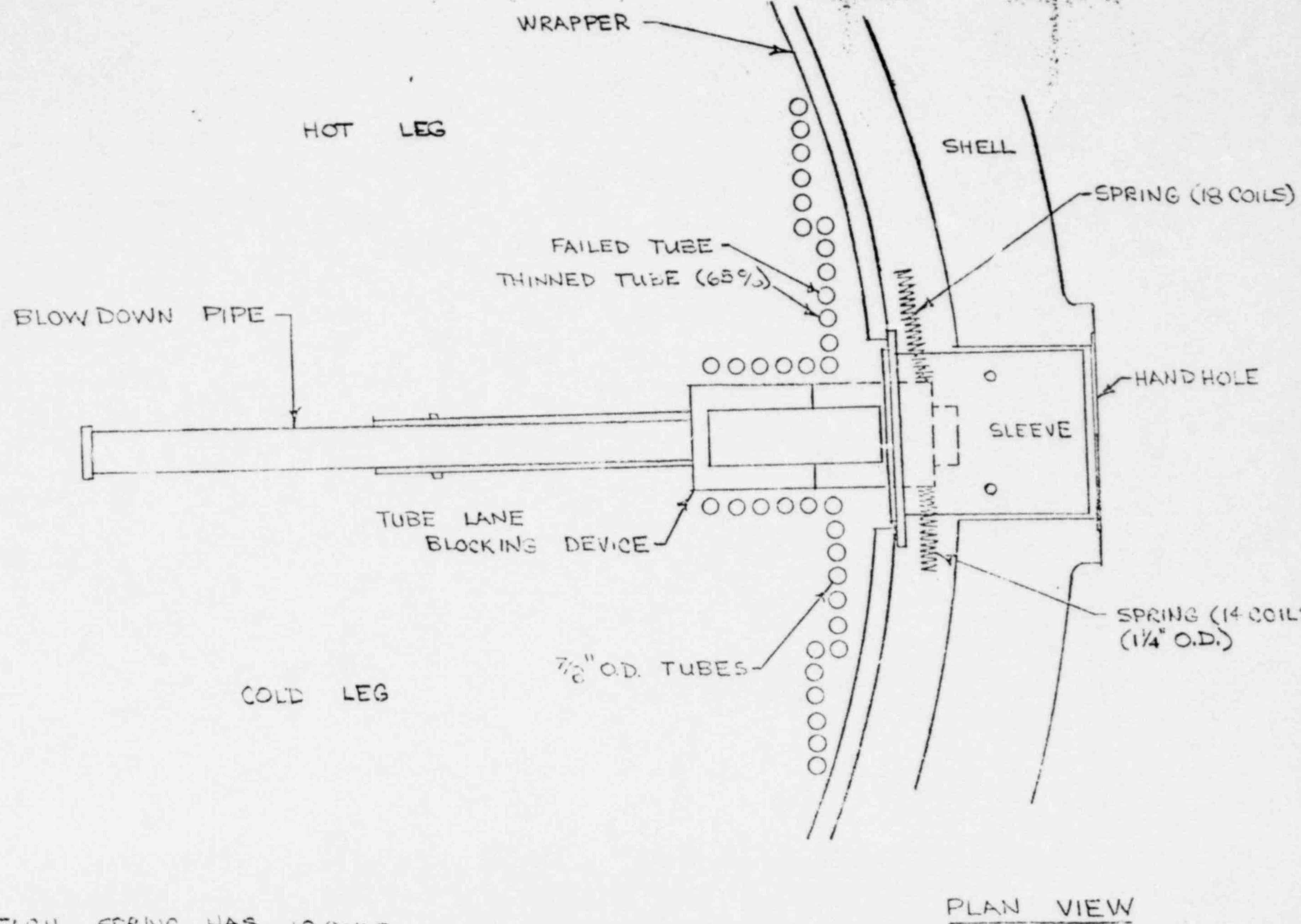


FIGURE 22

SKETCH OF LEAKING TUBE AND ADJACENT TUBES



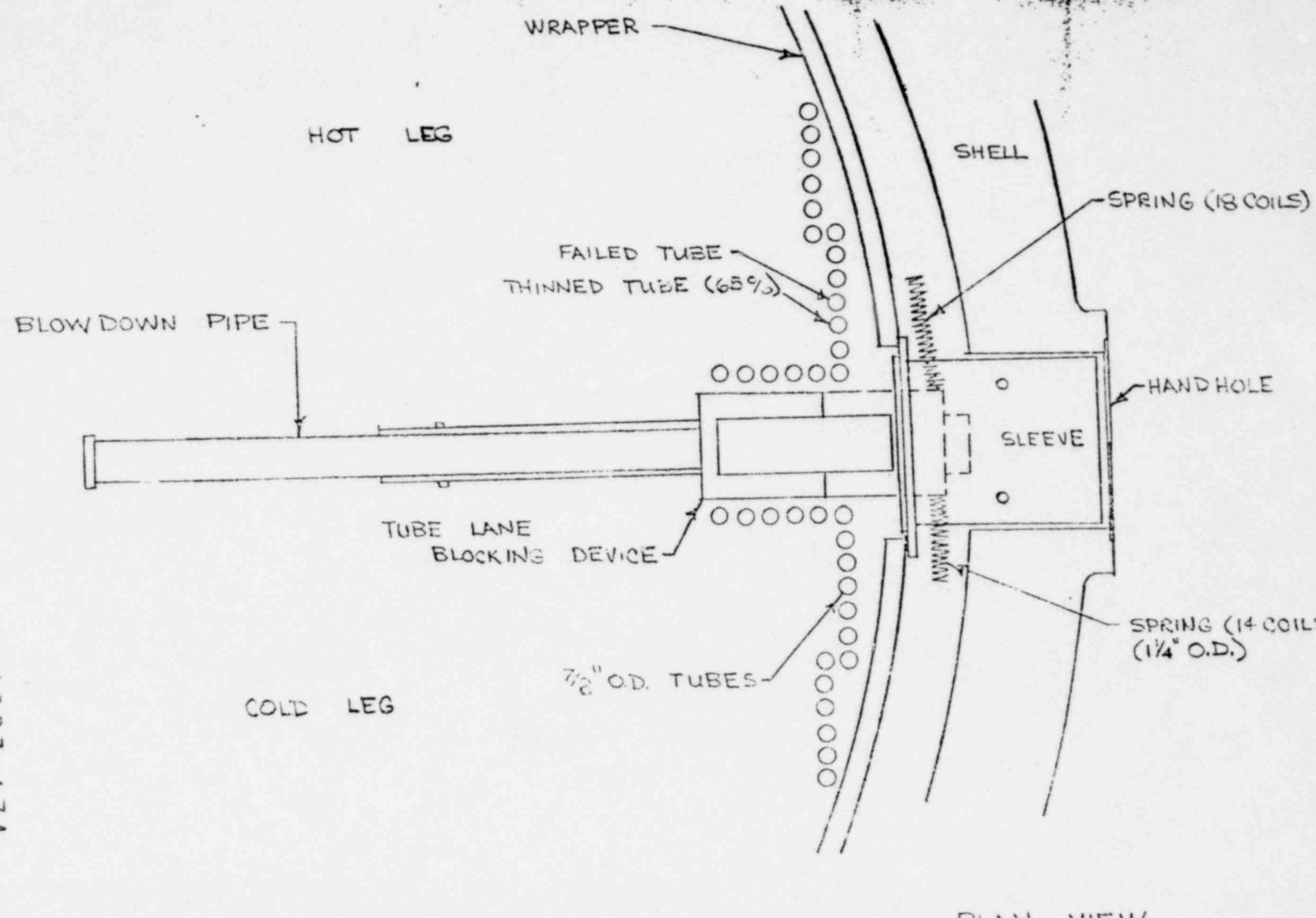
* EACH SPRING HAS 18 COILS

FIGURE 23

OVERHEAD VIEW- FAILED TUBE AREA

POOR ORIGINAL

1203 173



* EACH SPRING HAS 18 COILS

FIGURE 23

OVERHEAD VIEW- FAILED TUBE AREA

POOR ORIGINAL

1203 174

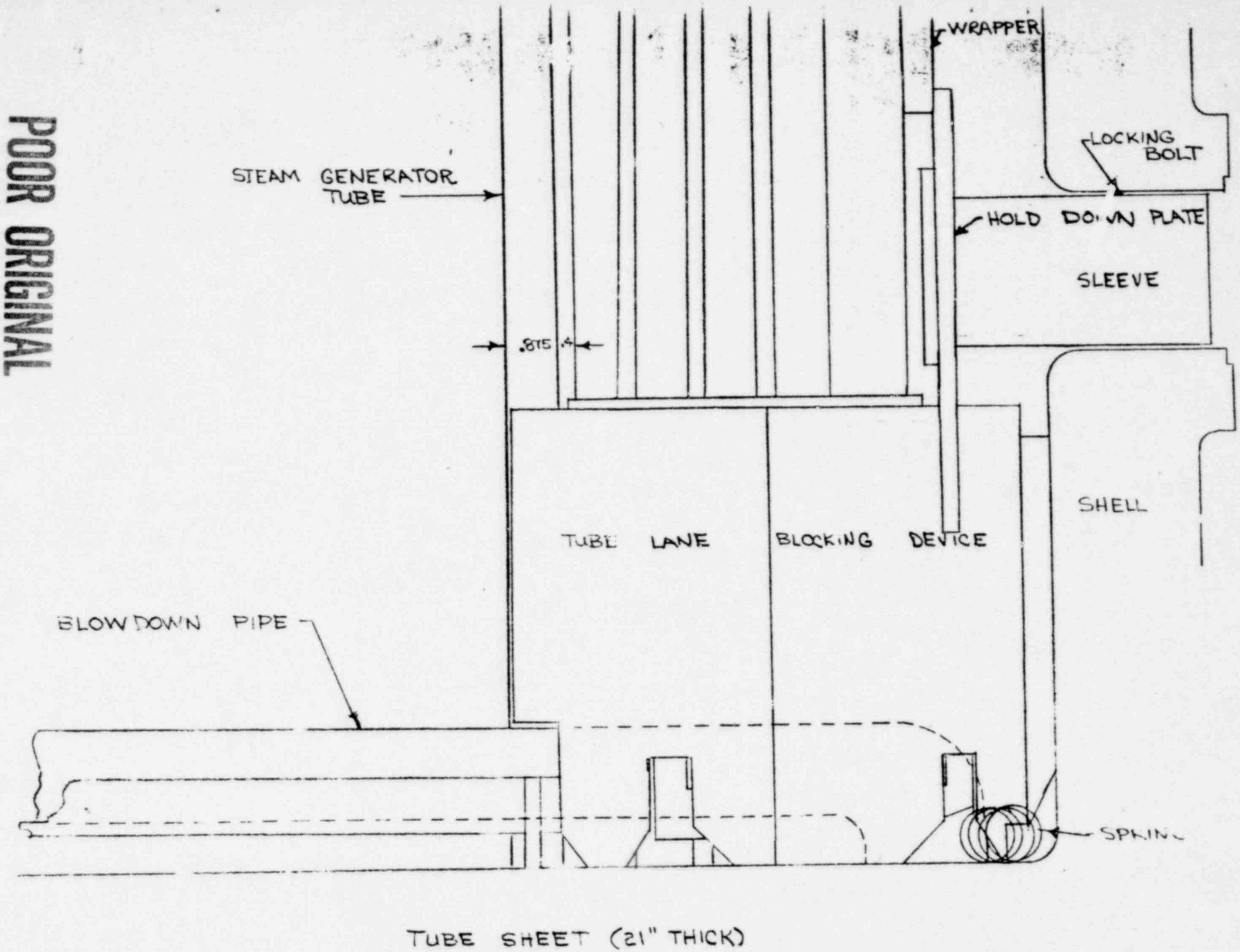


FIGURE 24

SIDE VIEW - FAILED TUBE AREA

POOR ORIGINAL

1203 175

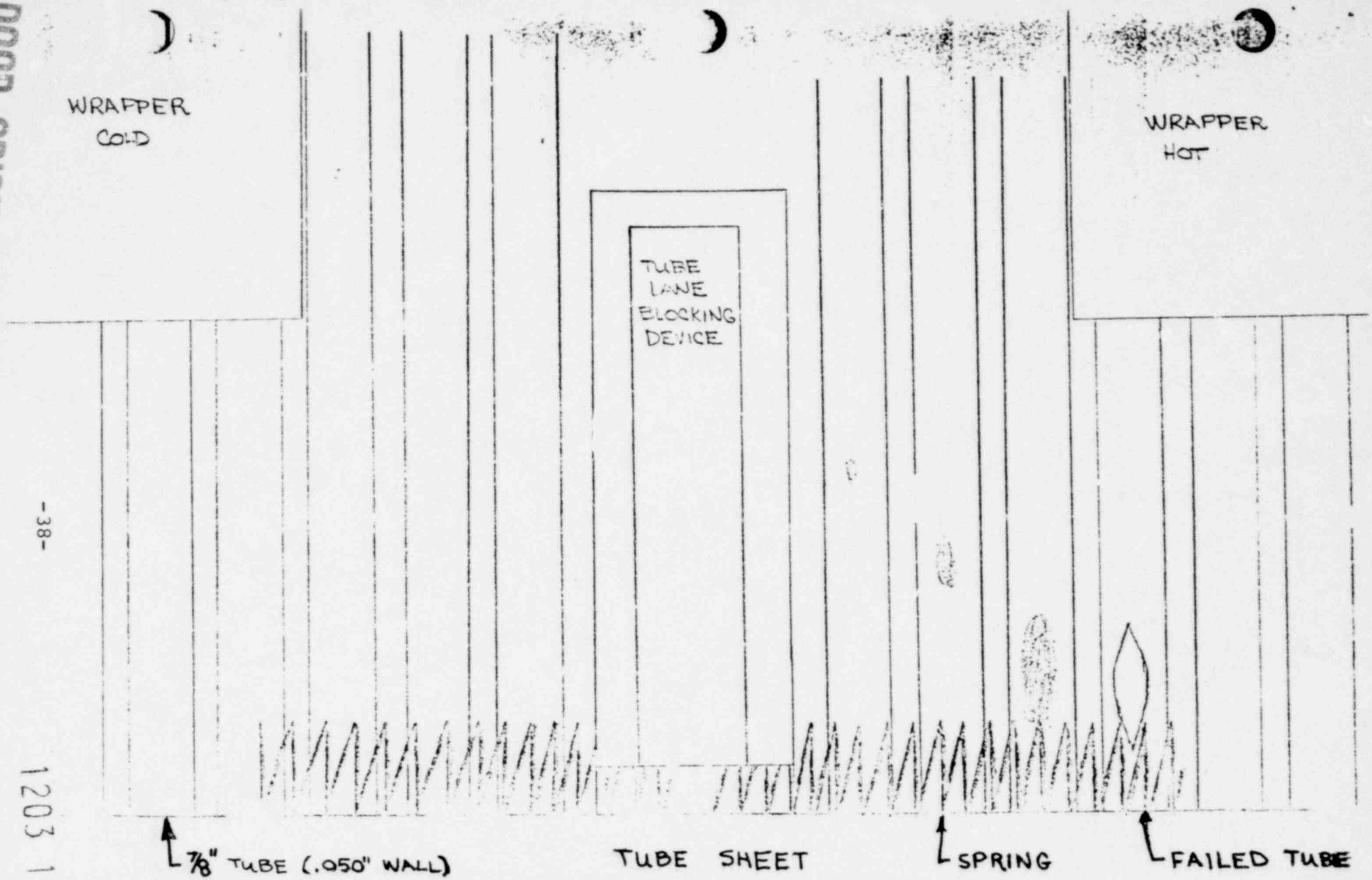


FIGURE 25

FRONT VIEW - FAILED TUBE AREA

FRONT VIEW

1203 176