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AUTH.NAME AUTHOR AFFILIATION
UTLEY,E.E. Carolina Power & Light Co.
RECIP.NAME RECIPIENT AFFILIATION
VARGA,S.A. Operating Reactors Branch 1

SUBJECT: Requests approval by 810828 to allow commencement of power operations.Actions taken prior to return to power & operating restrictions in proposed license conditions insure safe operation for remainder of Cycle 8. 566 RPL

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AUG 27 1981

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CP&L

Carolina Power & Light Company

August 21, 1981

FILE: NG-3514(R)

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RECEIVED AUG 24 1981 U.S. NUCLEAR REGULATORY COMMISSION

Office of Nuclear Reactor Regulation
Attention: Mr. Steven A. Varga, Chief
Operating Reactors Branch No. 1
United States Nuclear Regulatory Commission
Washington, D.C. 20555

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
DOCKET NO. 50-261
LICENSE NO. DPR-23
STEAM GENERATOR RECOVERY PROGRAM

Dear Mr. Varga:

Representatives from Carolina Power & Light Company (CP&L) and Westinghouse Electric Corporation met with your staff on August 13, 1981 to discuss the results of the recent steam generator inspection at H. B. Robinson Unit 2.

In addition to a discussion of the results of this inspection, CP&L outlined the actions planned to be taken prior to startup of the unit and during the remainder of the current operating cycle. These programs are outlined below:

Actions Prior to Return to Power Operation: In addition to plugging all steam generator tubes with indications > 47%, CP&L recognizes the need to change the environment in the steam generators which may be contributing to the degradation of the tubes. Therefore, CP&L will sludge-lance all three steam generators for bulk sludge removal. In addition, we will also perform crevice flushing in each steam generator to further reduce contaminants left after sludge lancing which are believed to contribute to degradation in that region of the steam generators.

Actions Following Return to Power Operation: In order to ensure the continued safe operation of H. B. Robinson and further improve the environment in the steam generators CP&L will take the following actions. These actions will be in effect from return of the unit to power operation until the completion of the current fuel cycle and are reflected in the proposed license condition (Attachment A).

a. A primary to secondary pressure test will be performed at 30 (± 25%) effective full power days (EFPD) of operation to ensure the integrity of the steam generators subsequent to startup.

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$4000.00

b. At approximately 90 EFPD of operation (end of core life) an eddy current examination will be performed. The scope of this inspection will be submitted to the NRC for approval at least 45 calendar days prior to the inspection.

c. During the remainder of the current cycle operations, the following steam generator tube leakage criteria will be in effect. Specifically, the plant will be shutdown if the verified primary to secondary leakage in one steam generator exceeds any of the following:

   1. A sudden increase of 0.1 gallon per minute (gpm) if the total leakage rate in that steam generator exceeds 0.2 gpm.

   2. If the leakage rate in that steam generator exceeds 0.2 gpm and an upward trend in leakage rate in excess of 0.02 gpm per day is verified. This trend will be established using at least five valid consecutive daily samples.

d. Should the plant be required to shut down to repair a steam generator tube leak as indicated in item (c) above, an inspection will be performed as mutually agreed upon by the NRC Staff and CP&L.

e. The NRC Staff will be provided with a summary of the results of the eddy current examination performed under item (d) above.

CP&L also recognizes the temperature dependency of the corrosion process occurring in the steam generators. As a result, H. B. Robinson will be operated at a power level to minimize T_H to as low a value as practicable consistent with the information provided in Attachment B.

Inspection Results: The results of the May, 1981 eddy current tests are contained in Attachment C. The results of the August, 1981 eddy current tests and examinations of the pulled steam generator tubes are contained in Attachment B.

Safety Evaluation: The safety evaluation justifying the return of H. B. Robinson to power operations is contained in Attachment B.

Conclusion: It is our conclusion that as a result of the actions being taken prior to return of the unit to power, and the operating restrictions described in the attached proposed license condition, H. B. Robinson can be safely

returned to an operational status for the remainder of cycle 8. It is therefore requested that approval be granted by August 28, 1981 to allow H. B. Robinson to commence power operations. We have enclosed a check for $4,000.00 in accordance with 10CFR 170.22 for the license condition. Please do not hesitate to contact my staff if you have any questions.

Yours very truly,

E. E. Utley

E. E. Utley
Executive Vice President
Power Supply and
Engineering & Construction

SDF/lr (NRC#8)
Attachment

Sworn to and subscribed before me this 21st day of August, 1981.

Franklin Murray

FRANKLIN MURRAY
NOTARY PUBLIC
WAKE COUNTY, N. C.

cc: Mr. J. D. Neighbors

My commission expires: October 4, 1981

ATTACHMENT A

"Proposed License Condition"

Carolina Power & Light Company (CP&L) proposes the following operating license condition be effective from the time H. B. Robinson Unit 2 returns to power operations subsequent to the August, 1981 shutdown until the unit is shutdown for refueling:

a. A primary pressure test shall be performed at 30 (± 25%) effective full power days (EFPD) of operation to ensure the integrity of the steam generators subsequent to startup.

b. At approximately 90 EFPD of operation (end of core life) an eddy current examination shall be performed. The scope of this inspection shall be submitted to the NRC for approval at least 45 calendar days prior to the inspection.

c. During the remainder of the cycle 8 operations, the following steam generator tube leakage criteria shall be in effect. Specifically, the plant shall be shutdown if the verified primary to secondary leakage in one steam generator exceeds any of the following:

   1. A sudden increase of 0.1 gallon per minute (gpm) if the total leakage rate in that steam generator exceeds 0.2 gpm.

   2. If the leakage rate in that steam generator exceeds 0.2 gpm and an upward trend in leakage rate in excees of 0.02 gpm per day is verified. This trend will be established using at least five valid consecutive daily samples.

d. Should the plant be required to shut down to repair a steam generator tube leak as indicated in item (c) above, an inspection shall be performed as mutually agreed upon by the NRC Staff and CP&L.

e. The NRC Staff shall be provided with a summary of the results of the eddy current examination performed under item (d) above.

ATTACHMENT B

"Steam Generator Repair and Preventive Measures Report"

CAROLINA POWER & LIGHT COMPANY
H. B. ROBINSON UNIT 2

STEAM GENERATOR REPAIR AND PREVENTATIVE MEASURES REPORT

August, 1981

1.0 INTRODUCTION

On July 30, 1981 the H. B. Robinson Unit 2 generating station of Carolina Power & Light Company was shutdown for reasons of primary to secondary leakage. Power operation was terminated before the technical specification limit was reached and the plant was cooled in a normal fashion. The resultant inspection of the unit revealed that two leaking tubes existed on the hot leg of steam generator B. The resulting inspection program was expanded to include all hot leg tubes of the three steam generators. This report documents the events surrounding the outage, the results of the inspection program (including evaluation of the pulled tubes) and the actions and operational procedures to be observed on return to power.

2.0 OPERATIONAL EVENTS PRECEEDING THE OUTAGE

Following the outage and inspection of May, 1981, H. B. Robinson Unit 2 returned to operation on June 12. The unit was operated at a power level of approximately 95%.

On July 30, 1981 an increase in the secondary side radiation level was observed following a secondary plant load swing of approximately 45 MWe. The unit was therefore taken off-line when the primary to secondary leakage rate was calculated to be 0.301 gpm.

3.0 RESULTS OF STEAM GENERATOR DIAGNOSTICS PROGRAM

3.1 EDDY CURRENT INSPECTION RESULTS

3.1.1 Normal Bobbin Probe Results

Eddy Current Indication Distributions

A preliminary analysis of the standard multi-frequency bobbin probe eddy current results was made for the steam generator A inlet, the steam generator B inlet and outlet, and steam generator C inlet and outlet data. The distribution, according to percentage of wall penetration in the tubesheet, crevice, support plate and U-bend regions, of the reported eddy current indications is shown for steam generator B inlet and outlet and steam generator C inlet legs evaluated to date in Tables 3.1.1 to 3.1.3. In these tables, the mean indication size, standard deviation, and total number of indications observed are also tabulated. Histrograms of the data tabulated in these tables are displayed for each of the evaluation (regions) of interest where data were obtained in Figures 3.1.1 to 3.1.10 inclusive. The data for steam generator A inlet and steam generator C outlet is in the process of being tabulated.

The spatial distributions of the reported eddy current indications across the steam generator A inlet, B inlet and outlet, and C inlet legs are displayed in the form of tubesheet maps in Figures 3.1.11 to 3.1.14 inclusive. The size range of each indication plotted is designated by a specific symbol, as shown in the legend to each of the Figures.

Eddy Current Indication Growth Calculations

The apparent growth statistics between the 5/81 and 8/81 inspections were calculated for those indications reported as $\geq$20% at both inspections. These statistics, as well as the distribution according to apparent growth, in the tubesheet, crevice, support plate, and U-bend regions of

each steam generator leg evaluated to date, are displayed in Tables 3.1.4 to 3.1.6. Although the tables for steam generator A inlet and steam generator C outlet are not available, the results are consistent with those shown in the tables for steam generator B inlet and outlet and steam generator C inlet.

3.1.2 Verification With "5 X 5" Probe Hot Leg

A novel design eddy current probe, designated the "5 X 5", was utilized to check the bobbin probe results. The design of this probe consists of two banks of series wired, surface-riding pancake coils differentially coupled, and thereby provides the sensitivity of surface-riding pancake coils in a straight-pull (as opposed to rotating) mode of test.

A sample of 22 tubes in S/G B and 54 tubes in S/G C were tested with the 5 X 5 probe.

The results of this special test showed no evidence of signals in the hot leg that were not already reported by the bobbin probe. Additionally, the signals found by the 5 X 5 probe were consistent with those found by the bobbin probe.

3.1.2 5 X 5 Cold Leg Experience

As a result of a tube leak in steam generator C cold leg, approximately 100 tubes were tested with the 5 X 5 probe. The results showed no significant growth of indications compared to the previous inspection.

TABLE 3.1.1

CPL-STEAM GENERATOR B HOT LEG

EDDY CURRENT ANALYSIS FOR CPL B HOT LEG AUGUST 1981

MEAN AND STANDARD DEVIATION OF EDDY CURRENT INDICATIONS

LOCATION	MEAN	STANDARD DEVIATION	NUMBER OF POINTS
BELOW THE TUBE SHEET	83.967	10.965	30
AT THE TUBE SHEET	38.472	20.486	388
AT THE SUPPORT PLATES	33.000	9.621	15
IN THE UBEND	29.323	6.710	31

DISTRIBUTION OF EDDY CURRENT INDICATIONS

LOCATION	PERCENTAGE OF WALL PENETRATION												
	DS	<20	20-26	27-33	34-40	41-47	48-54	55-61	62-68	69-75	76-82	83-89	90-96
BELOW THE TUBE SHEET	8	0	0	0	0	0	0	2	2	2	4	12	8
AT THE TUBE SHEET	1	475	135	98	55	17	20	4	12	14	20	13	2
AT THE SUPPORT PLATES	0	4	4	4	5	1	0	1	0	0	0	0	0
IN THE UBEND	0	28	13	10	5	3	0	0	0	0	0	0	0
TOTALS	9	507	152	112	65	21	20	7	14	16	24	25	10

TABLE 3.1.2

CPL - STEAM GENERATOR B - COLD LEG

EDDY CURRENT ANALYSIS FOR CPL B COLD LEG AUGUST 1981

MEAN AND STANDARD DEVIATION OF EDDY CURRENT INDICATIONS

LOCATION	MEAN	STANDARD DEVIATION	NUMBER OF POINTS
BELOW THE TUBE SHEET	0.000	0.000	0
AT THE TUBE SHEET	32.872	7.910	94
AT THE SUPPORT PLATES	30.667	6.346	6
IN THE UBEND	0.000	0.000	0

DISTRIBUTION OF EDDY CURRENT INDICATIONS

LOCATION	PERCENTAGE OF WALL PENETRATION												
	DS	<20	20-26	27-33	34-40	41-47	48-54	55-61	62-68	69-75	76-82	83-89	90-96
BELOW THE TUBE SHEET	0	0	0	0	0	0	0	0	0	0	0	0	0
AT THE TUBE SHEET	0	31	25	21	31	15	2	0	0	0	0	0	0
AT THE SUPPORT PLATES	0	0	2	3	0	1	0	0	0	0	0	0	0
IN THE UBEND	0	0	0	0	0	0	0	0	0	0	0	0	0
	---	---	---	---	---	---	---	---	---	---	---	---	---
TOTALS	0	31	27	24	31	16	2	0	0	0	0	0	0

TABLE 3.1.3
CPL-STEAM GENERATOR C HOT LEG

EDDY CURRENT ANALYSIS FOR CPL C HOT LEG AUGUST 1981

MEAN AND STANDARD DEVIATION OF EDDY CURRENT INDICATIONS

Location	Mean	Standard Deviation	Number of Points
Below the Tube Sheet	57.500	32.665	7
At the Tube Sheet	36.883	19.813	400
At the Support Plates	30.333	5.508	6
In the U Bend	29.429	6.949	9

DISTRIBUTION OF EDDY CURRENT INDICATIONS

Location	Percentage of Wall Penetration												
	DS	<20	20-26	27-33	34-40	41-47	48-54	55-61	62-68	69-75	76-82	83-89	90-96
Below the Tube Sheet	2	0	1	0	0	2	1	0	1	0	0	0	0
At the Tube Sheet	1	177	80	63	30	8	1	3	7	6	14	8	2
At the Support Plates	0	2	1	1	1	0	1	0	0	0	0	0	0
In the U Bend	0	1	2	3	2	0	1	0	0	0	0	0	0
TOTALS	3	180	84	67	33	10	4	3	8	6	14	8	2

TABLE 3.1.4

MEAN AND STANDARD DEVIATION OF GROWTHS

CPL - STEAM GENERATOR B - HOT LEG

LOCATION	MEAN	STANDARD DEVIATION	NUMBER OF POINTS
BELOW THE TUBE SHEET	0.000	0.000	0
AT THE TUBE SHEET	.031	9.123	136
AT THE SUPPORT PLATES	-3.111	5.667	9
IN THE UBEND	-2.765	5.286	17

DISTRIBUTION OF GROWTH EVALUATIONS

LOCATION	PERCENTAGE OF WALL PENETRATION											
	-20--16	-15--11	-10--6	-5--1	0- 4	5- 9	10-14	15-19	20-24	25-29	30-34	35-39	40-44
BELOW THE TUBE SHEET	0	0	0	0	0	0	0	0	0	0	0	0
AT THE TUBE SHEET	1	7	14	40	47	17	3	4	1	0	0	2
AT THE SUPPORT PLATES	0	1	2	3	3	0	0	0	0	0	0	0
IN THE UBEND	1	0	4	4	7	1	0	0	0	0	0	0
	---	---	---	---	---	---	---	---	---	---	---	---
TOTALS	2	8	20	47	57	18	3	4	1	0	0	2

CPL - STEAM GENERATOR B - COLD LEG

TABLE 3.1.5

MEAN AND STANDARD DEVIATION OF GROWTHS

LOCATION	MEAN	STANDARD DEVIATION	NUMBER OF POINTS
BELOW THE TUBE SHEET	0.000	0.000	0
AT THE TUBE SHEET	-.525	5.435	40
AT THE SUPPORT PLATES	8.500	.707	2
IN THE UBEND	0.000	0.000	0

DISTRIBUTION OF GROWTH EVALUATIONS

PERCENTAGE OF WALL PENETRATION

LOCATION	-20--16	-15--11	-10--6	-5--1	0- 4	5- 9	10-14	15-19	20-24	25-29	30-34	35-39	40-[illegible]
BELOW THE TUBE SHEET	0	0	0	0	0	0	0	0	0	0	0	[illegible]	
AT THE TUBE SHEET	0	1	5	15	11	7	1	0	0	0	0	[illegible]	
AT THE SUPPORT PLATES	0	0	0	0	0	2	0	0	0	0	0	[illegible]	
IN THE UBEND	0	0	0	0	0	0	0	0	0	0	0	[illegible]	
	---	---	---	---	---	---	---	---	---	---	---	---	---
TOTALS	0	1	5	15	11	9	1	0	0	0	0		

TABLE 3.1.6

CPL STEAM GENERATOR C. HOT LEG

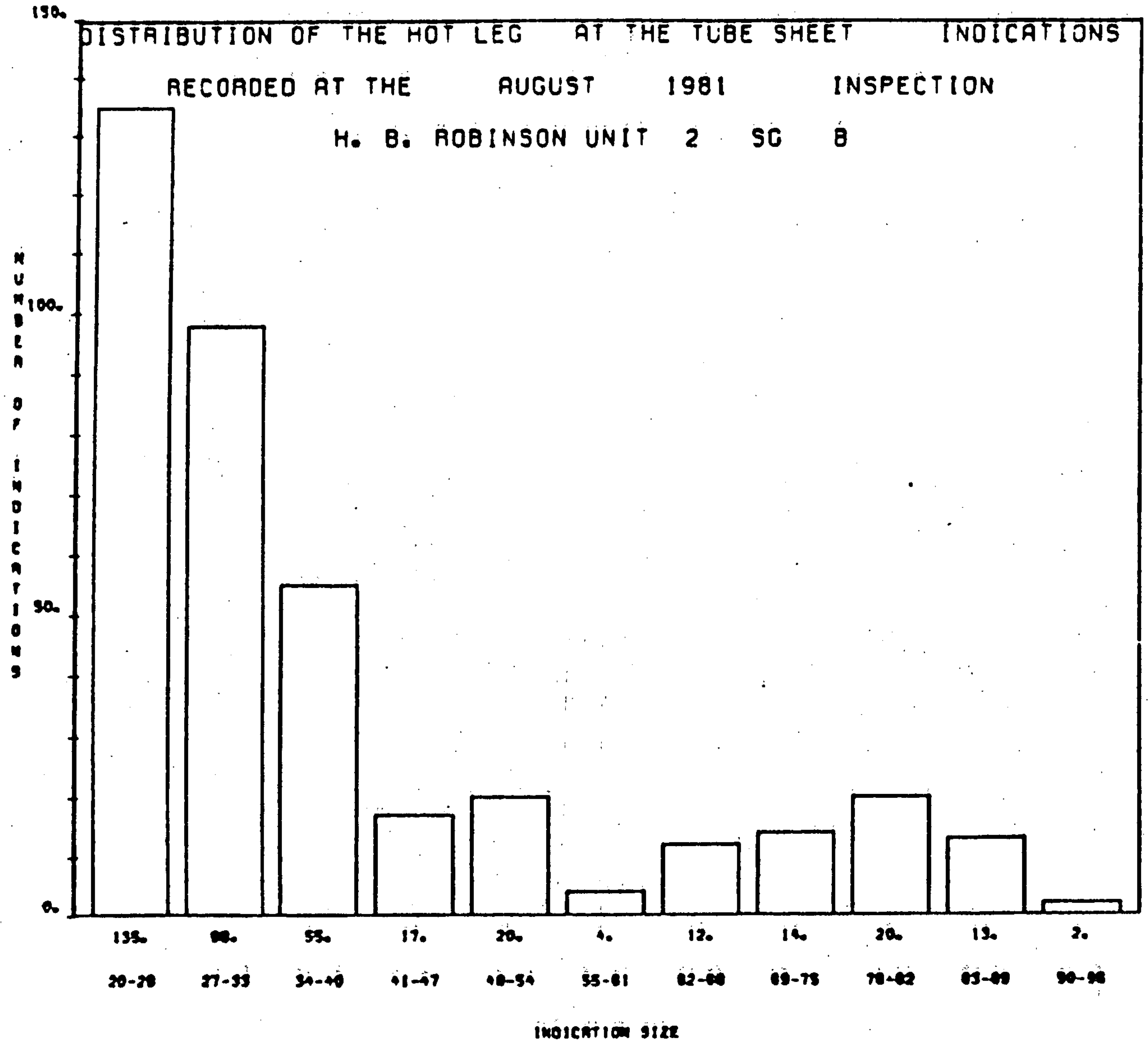
MEAN AND STANDARD DEVIATION OF GROWTHS

LOCATION	MEAN	STANDARD DEVIATION	NUMBER OF POINTS
BELOW THE TUBE SHEET	0.000	0.000	0
AT THE TUBE SHEET	1.239	7.126	92
AT THE SUPPORT PLATES	0.000	2.646	3
IN THE UBEND	-1.000	4.082	4

DISTRIBUTION OF GROWTH EVALUATIONS

LOCATION	PERCENTAGE OF WALL PENETRATION												
	-20--16	-15--11	-10--6	-5--1	0- 4	5- 9	10-14	15-19	20-24	25-29	30-34	35-39	40-44
BELOW THE TUBE SHEET	0	0	0	0	0	0	0	0	0	0	0	0	
AT THE TUBE SHEET	0	1	7	23	47	10	2	2	0	0	0	0	
AT THE SUPPORT PLATES	0	0	0	2	1	0	0	0	0	0	0	0	
IN THE UBEND	0	0	0	3	0	1	0	0	0	0	0	0	
	---	---	---	---	---	---	---	---	---	---	---	---	
TOTALS	0	1	7	28	48	11	2	2	0	0	0	0	

FIGURE 3.1.1



DISTRIBUTION OF THE HOT LEG AT THE TUBE SHEET INDICATIONS
RECORDED AT THE AUGUST 1981 INSPECTION
H. B. ROBINSON UNIT 2 SG B
NUMBER OF INDICATIONS
150.
100.
50.
0.
135.
98.
55.
17.
20.
4.
12.
14.
20.
13.
2.
20-26
27-33
34-40
41-47
48-54
55-61
62-68
69-75
76-82
83-89
90-96
INDICATION SIZE

FIGURE 3.1.2

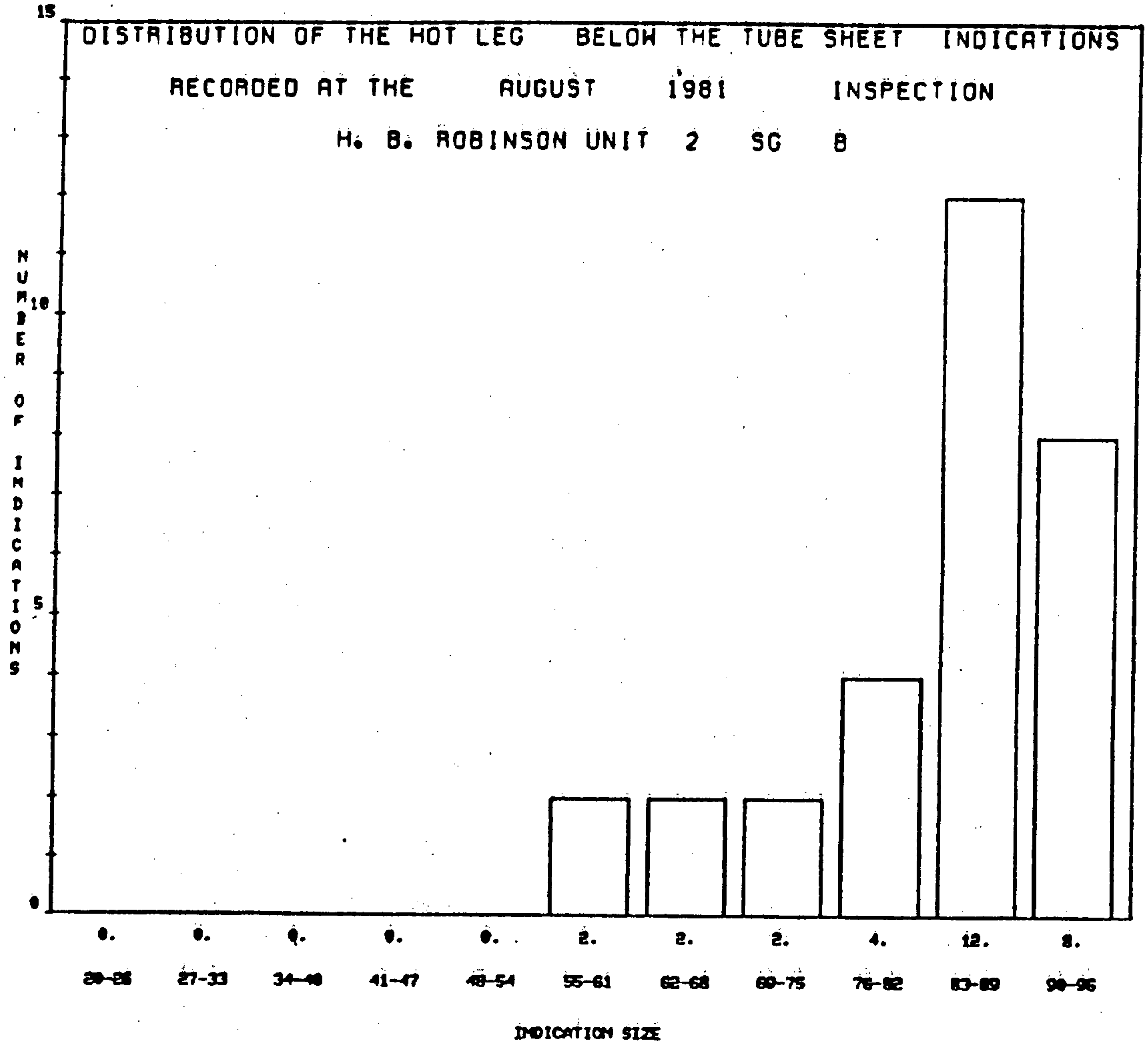

DISTRIBUTION OF THE HOT LEG BELOW THE TUBE SHEET INDICATIONS
RECORDED AT THE AUGUST 1981 INSPECTION
H. B. ROBINSON UNIT 2 SG B
NUMBER OF INDICATIONS
15
10
5
0
0. 0. 0. 0. 0. 2. 2. 2. 4. 12. 8.
20-26 27-33 34-40 41-47 48-54 55-61 62-68 69-75 76-82 83-89 90-96
INDICATION SIZE

FIGURE 3.1.3

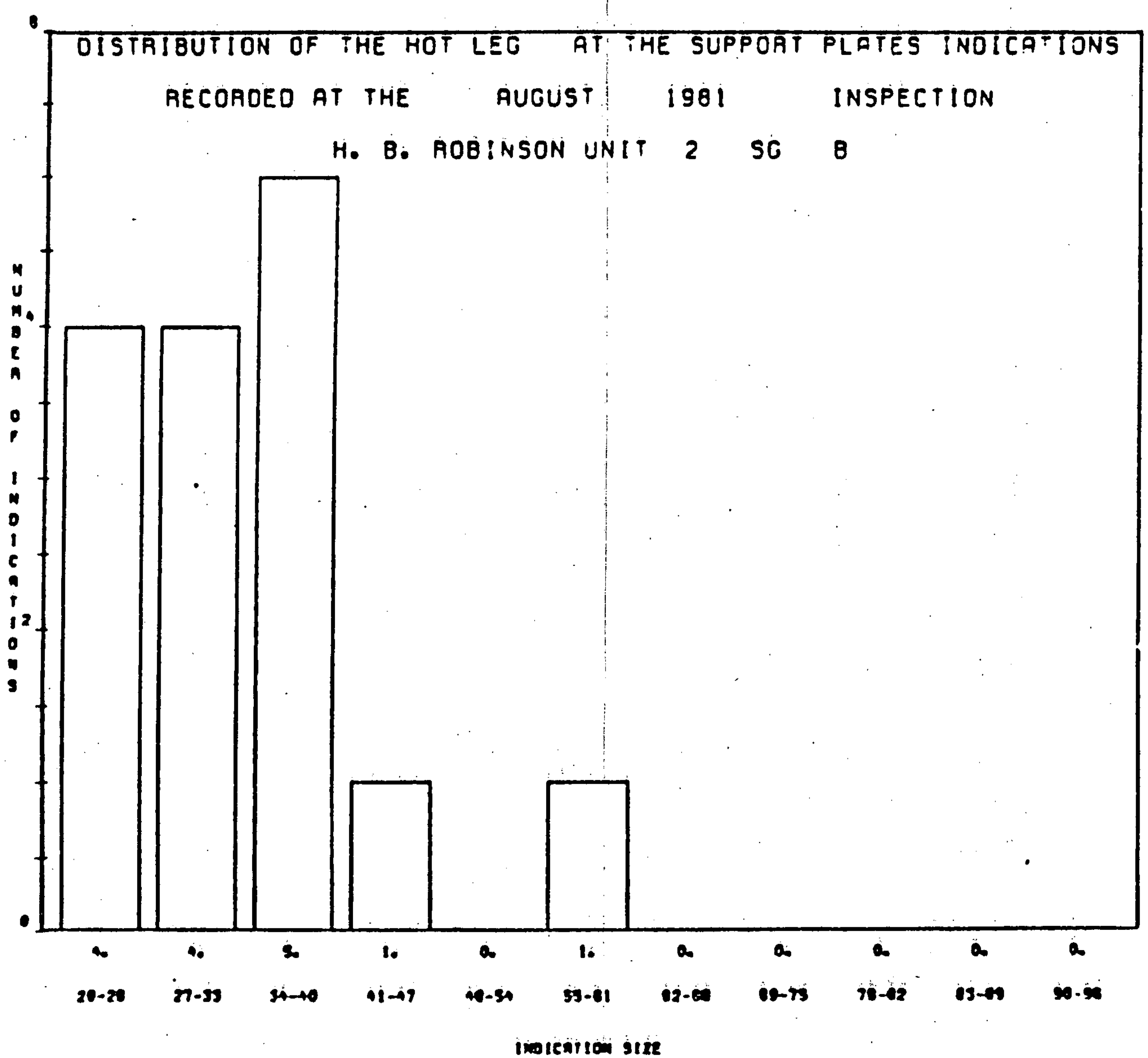
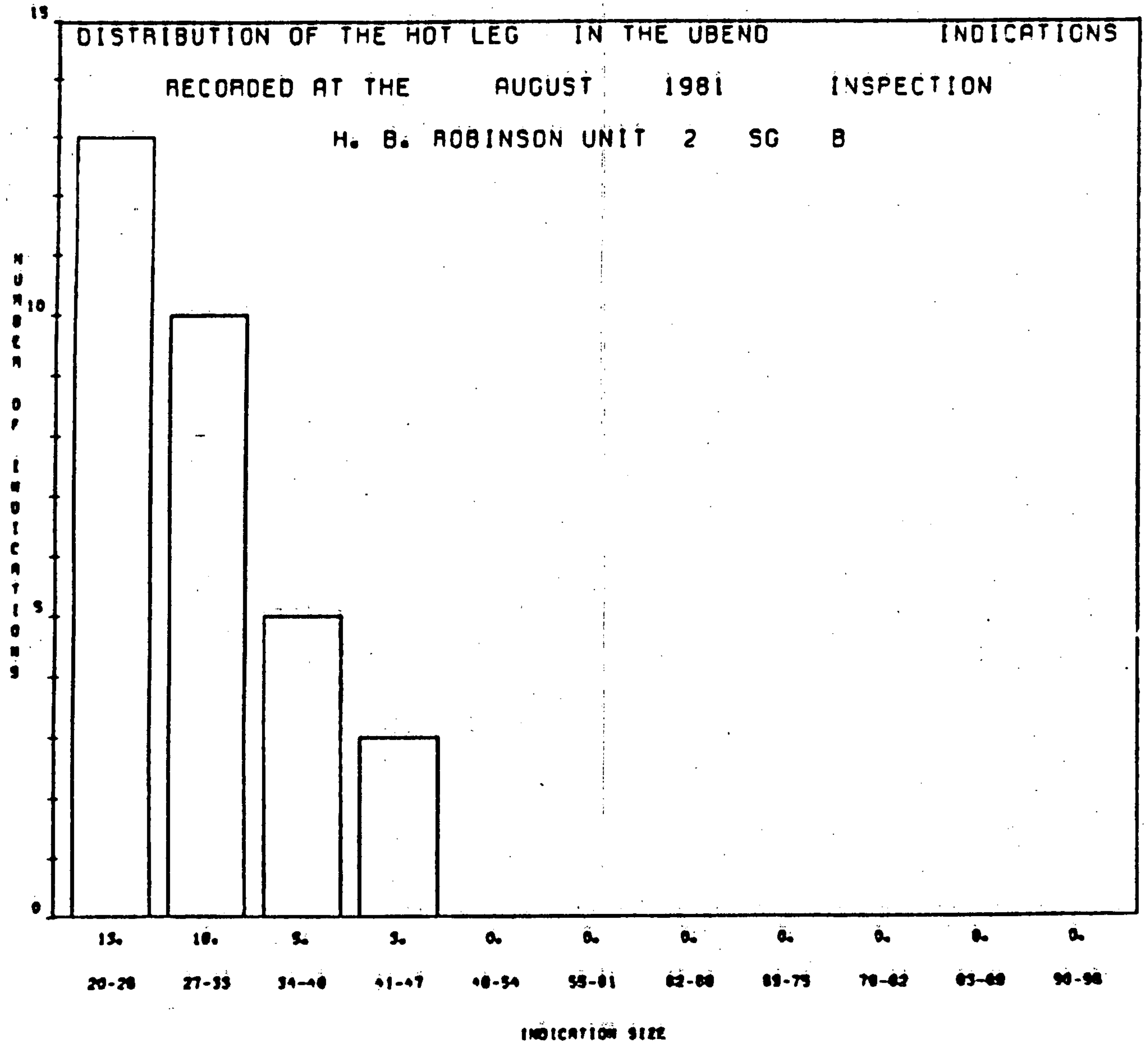

DISTRIBUTION OF THE HOT LEG AT THE SUPPORT PLATES INDICATIONS
RECORDED AT THE AUGUST 1981 INSPECTION
H. B. ROBINSON UNIT 2 SG B
NUMBER OF INDICATIONS
8
4
2
0
4.
4.
5.
1.
0.
1.
0.
0.
0.
0.
0.
20-26
27-33
34-40
41-47
48-54
55-61
62-68
69-75
76-82
83-89
90-96
INDICATION SIZE

FIGURE 3.1.4



DISTRIBUTION OF THE HOT LEG IN THE UBEND INDICATIONS
RECORDED AT THE AUGUST 1981 INSPECTION
H. B. ROBINSON UNIT 2 SG B
NUMBER OF INDICATIONS
15
10
5
0
13.
10.
5.
3.
0.
0.
0.
0.
0.
0.
0.
27-33
34-40
41-47
69-75
INDICATION SIZE

FIGURE 3.1.5

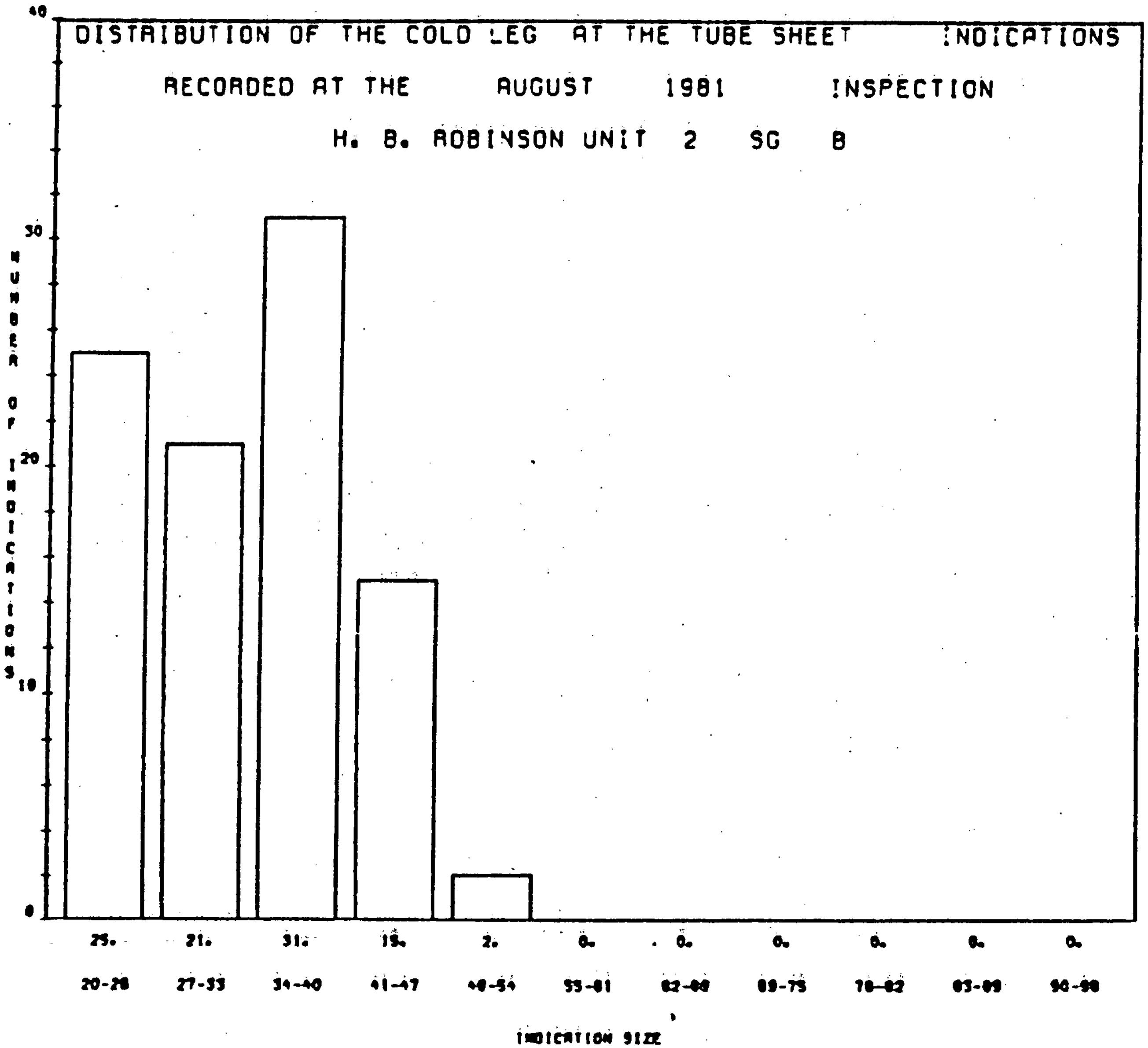

DISTRIBUTION OF THE COLD LEG AT THE TUBE SHEET INDICATIONS
RECORDED AT THE AUGUST 1981 INSPECTION
H. B. ROBINSON UNIT 2 SG B
NUMBER OF INDICATIONS
40
30
20
10
0
25.
21.
31.
15.
2.
0.
0.
0.
0.
0.
0.
20-26
27-33
34-40
41-47
48-54
55-61
62-68
69-75
76-82
83-89
90-96
INDICATION SIZE

FIGURE 3.1.6

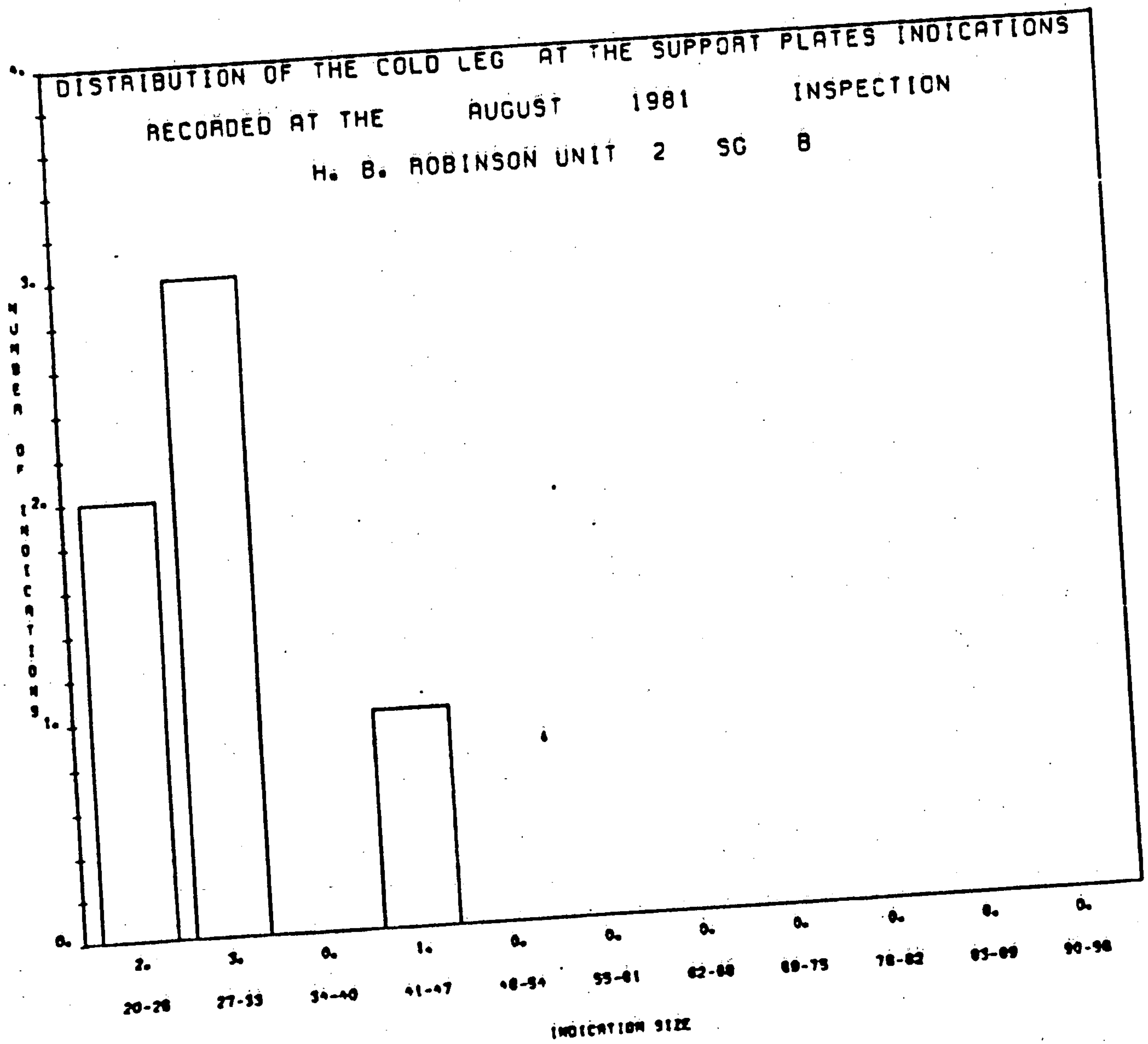

DISTRIBUTION OF THE COLD LEG AT THE SUPPORT PLATES INDICATIONS
RECORDED AT THE AUGUST 1981 INSPECTION
H. B. ROBINSON UNIT 2 SG B
NUMBER OF INDICATIONS
INDICATION SIZE

FIGURE 3.1.7

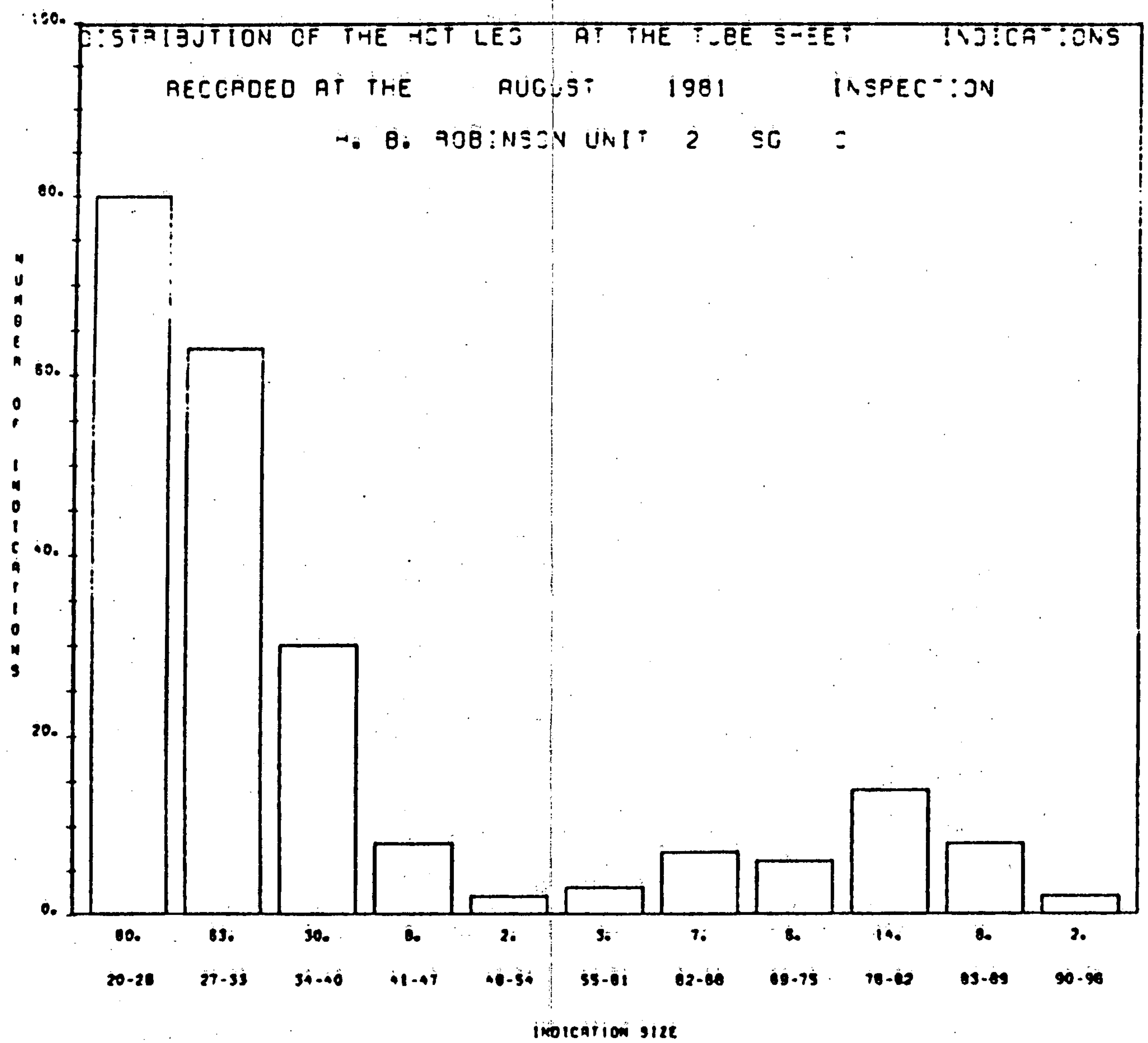

DISTRIBUTION OF THE HOT LEG AT THE TUBE SHEET INDICATIONS
RECORDED AT THE AUGUST 1981 INSPECTION
H. B. ROBINSON UNIT 2 SG C
NUMBER OF INDICATIONS
100.
80.
60.
40.
20.
0.
80.
63.
30.
8.
2.
3.
7.
6.
14.
8.
2.
20-26
27-33
34-40
41-47
48-54
55-61
62-68
69-75
76-82
83-89
90-96
INDICATION SIZE

FIGURE 3.1.8

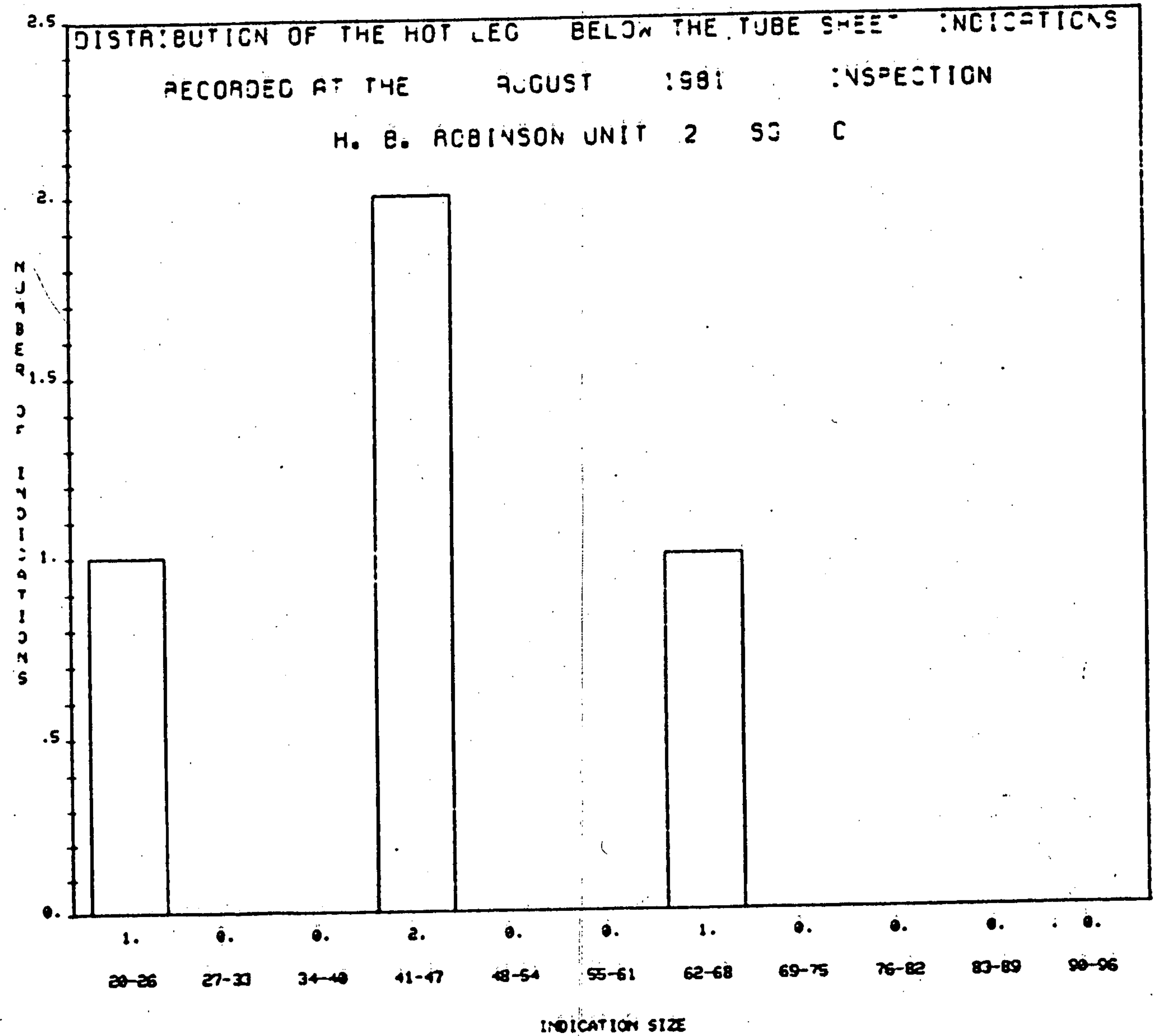

DISTRIBUTION OF THE HOT LEG BELOW THE TUBE SHEET INDICATIONS
RECORDED AT THE AUGUST 1981 INSPECTION
H. B. ROBINSON UNIT 2 SG C
NUMBER OF INDICATIONS
2.5
2.
1.5
1.
.5
0.
1.
0.
0.
2.
0.
0.
1.
0.
0.
0.
0.
20-26
27-33
34-40
41-47
48-54
55-61
62-68
69-75
76-82
83-89
90-96
INDICATION SIZE

FIGURE 3.1.9

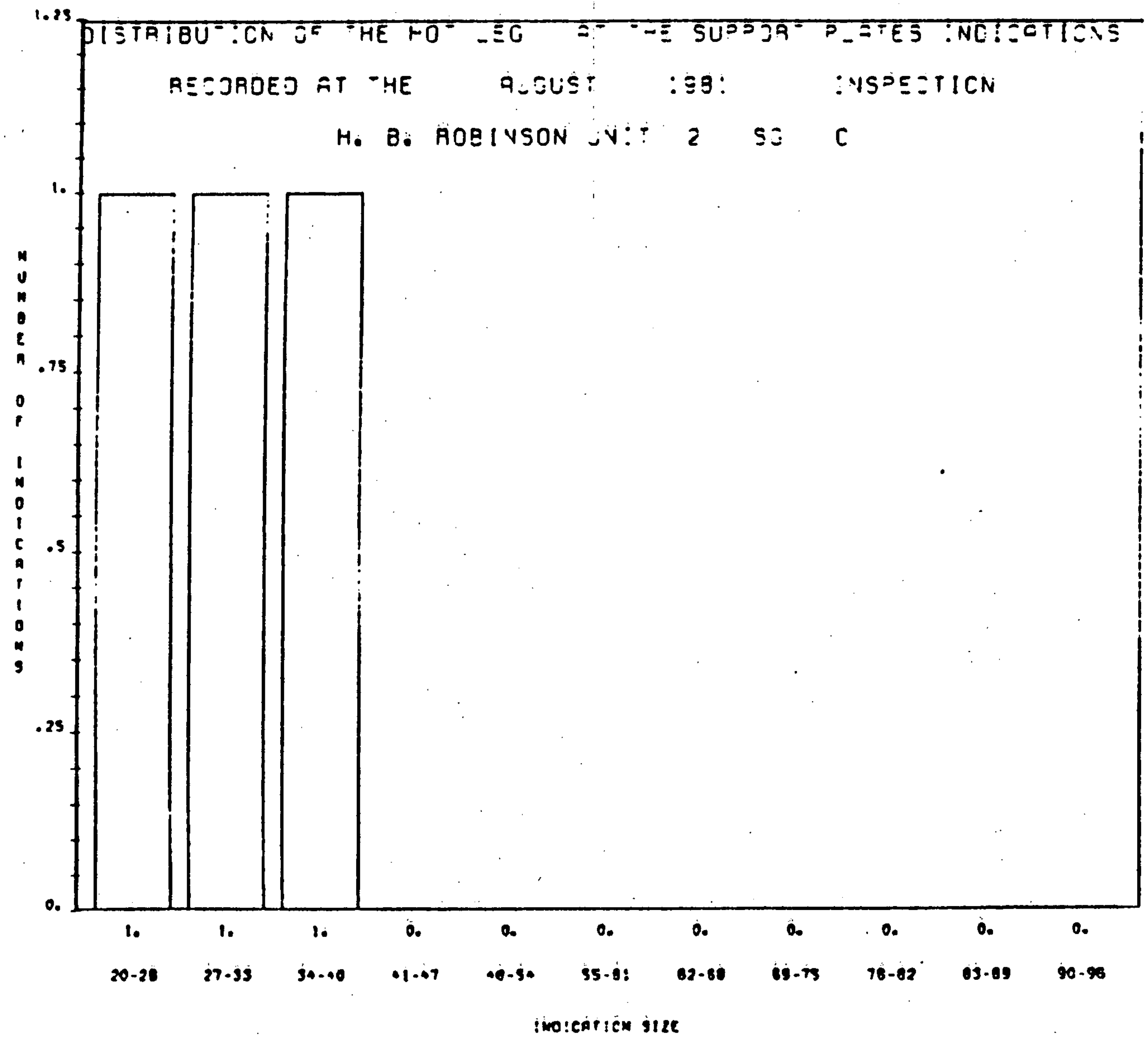
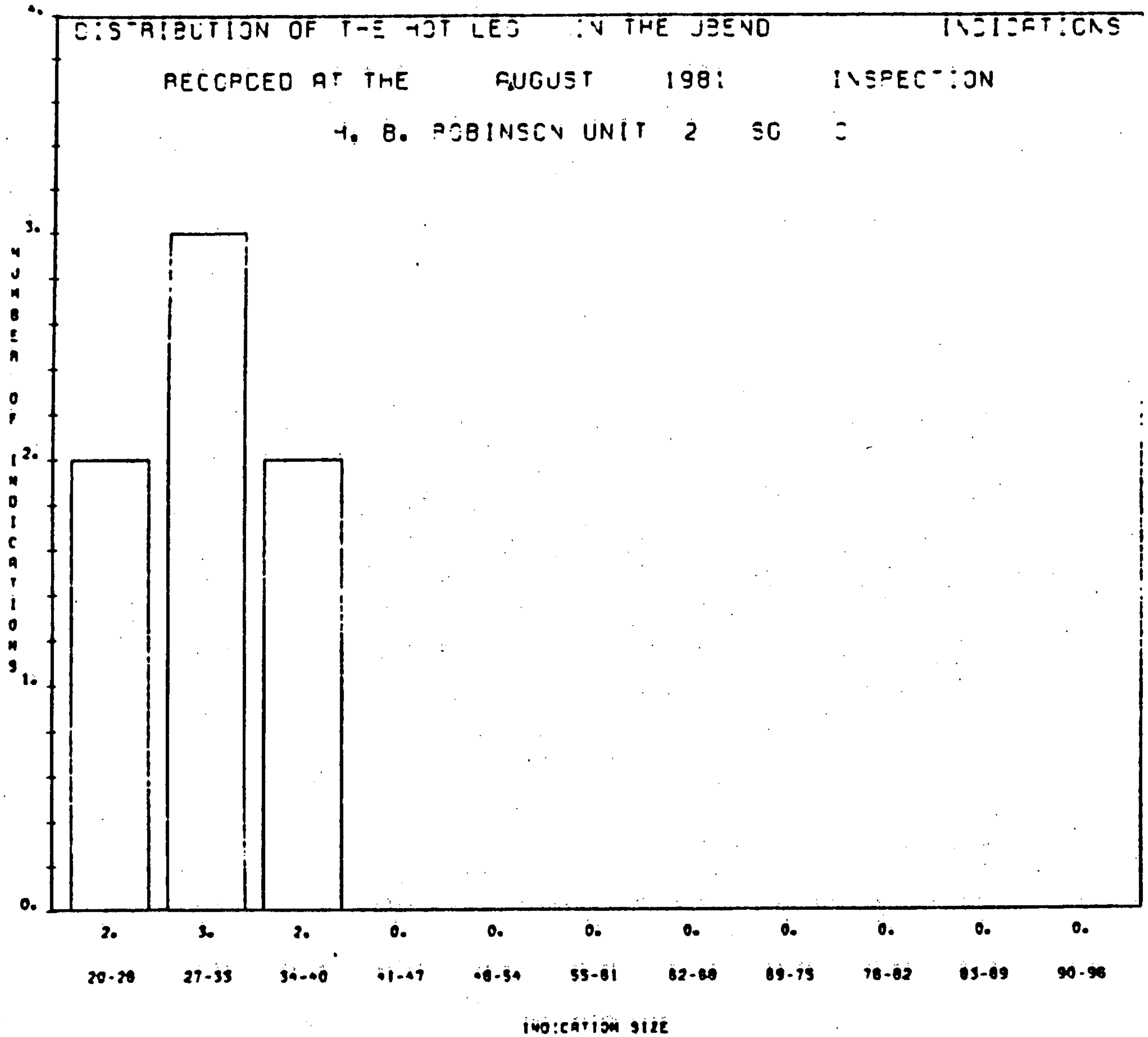

DISTRIBUTION OF THE HOT LEG AT THE SUPPORT PLATES INDICATIONS
RECORDED AT THE AUGUST 1981 INSPECTION
H. B. ROBINSON UNIT 2 SG C
NUMBER OF INDICATIONS
1.25
1.
.75
.5
.25
0.
1.
1.
1.
0.
0.
0.
0.
0.
0.
0.
0.
20-26
27-33
34-40
41-47
48-54
55-61
62-68
69-75
76-82
83-89
90-96
INDICATION SIZE

FIGURE 3.1.10



DISTRIBUTION OF THE HOT LEG IN THE UBEND INDICATIONS
RECORDED AT THE AUGUST 1981 INSPECTION
H. B. ROBINSON UNIT 2 SG C
NUMBER OF INDICATIONS
4.
3.
2.
1.
0.
2.
3.
2.
0.
0.
0.
0.
0.
0.
0.
0.
20-26
27-33
34-40
41-47
48-54
55-61
62-68
69-75
76-82
83-89
90-96
INDICATION SIZE

Figure 3.1.11

SERIES 44

CPL-A

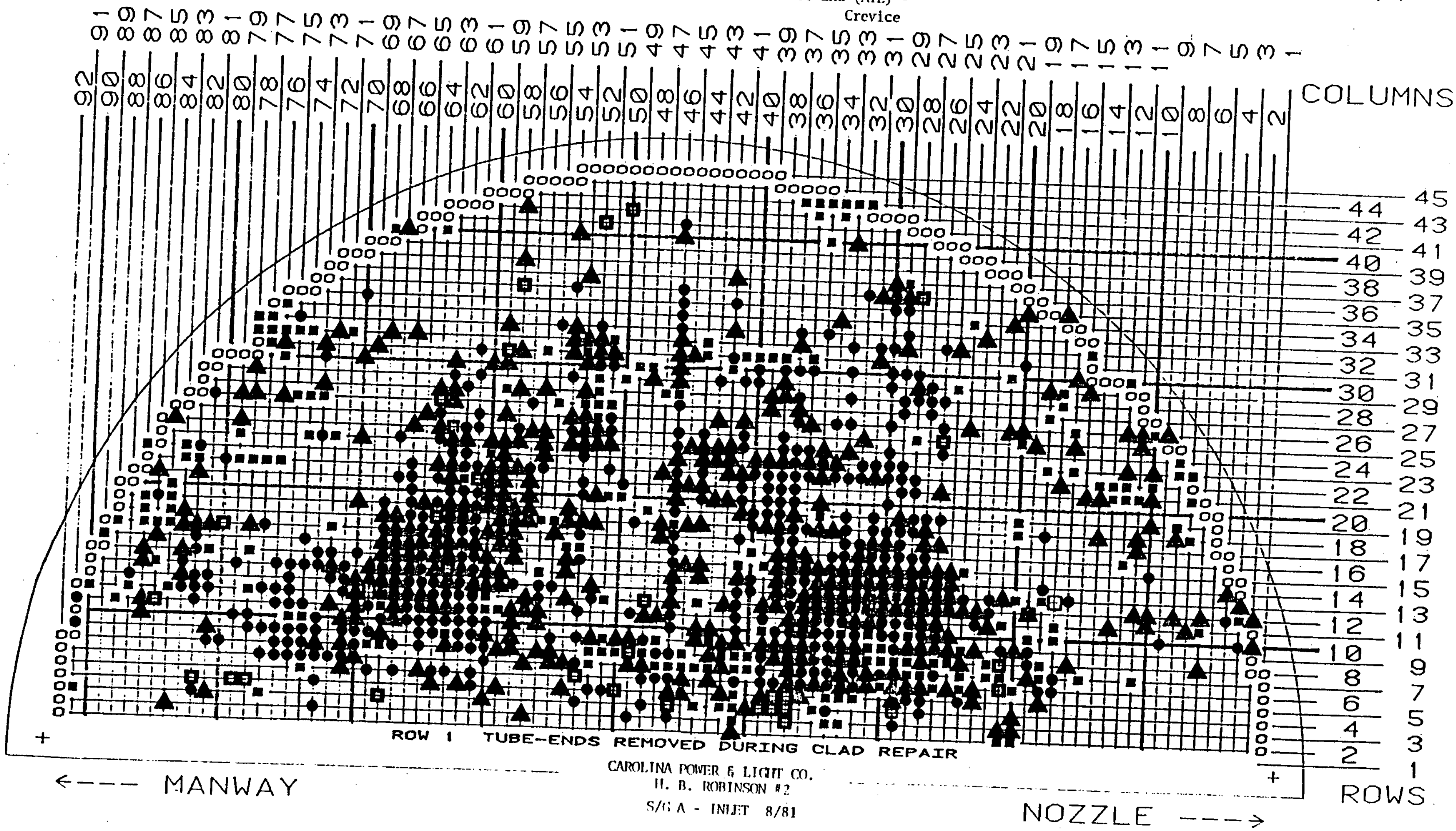
○ = <20% or Distorted
△ = 20-47%
□ = ≥48%

COLOR CODE

■ = U-Bend; AVB; ≥2 1/2" A6TSP
■ = Tube Support Plate (TSP) &≤2 1/2" A6TSP

COLOR CODE

■ = Above Tubesheet (ATS)
■ = Top Tubesheet (TTS)
■ = Above Tube End (ATE) - Crevice



CAROLINA POWER & LIGHT CO.
H. B. ROBINSON #2
S/G A - INLET 8/81

LEGEND: = <20% or Distorted
△ = 20-47%
□ = ≥48%

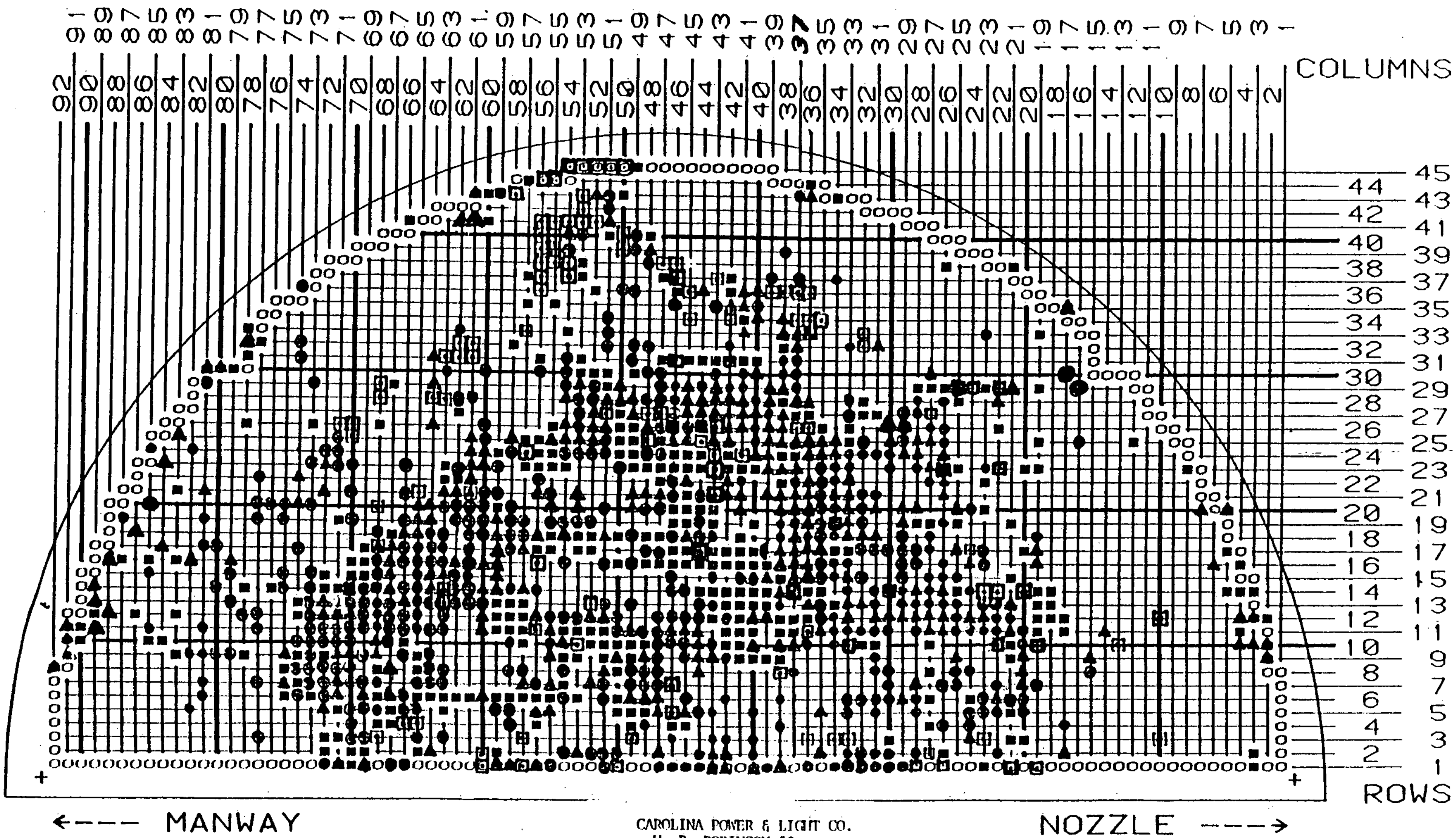
COLOR CODE
■ = U-Bend; AVB; >2 1/2" A6TSP
■ = Tube Support Plate (TSP) & ≤2 1/2" A6TSP

COLOR CODE
■ = Above Tubesheet (ATS)
■ = Top Tubesheet (TTS)
■ = Above Tube End (ATE)-Crevice

Figure 5.1.12

SERIES 44

CPL-B



CAROLINA POWER & LIGHT CO.
H. B. ROBINSON #2
S/G B - INLET 8/81

END: ○ = < 20% or Distorted Signal
△ = 20-47%
□ = ≥48%

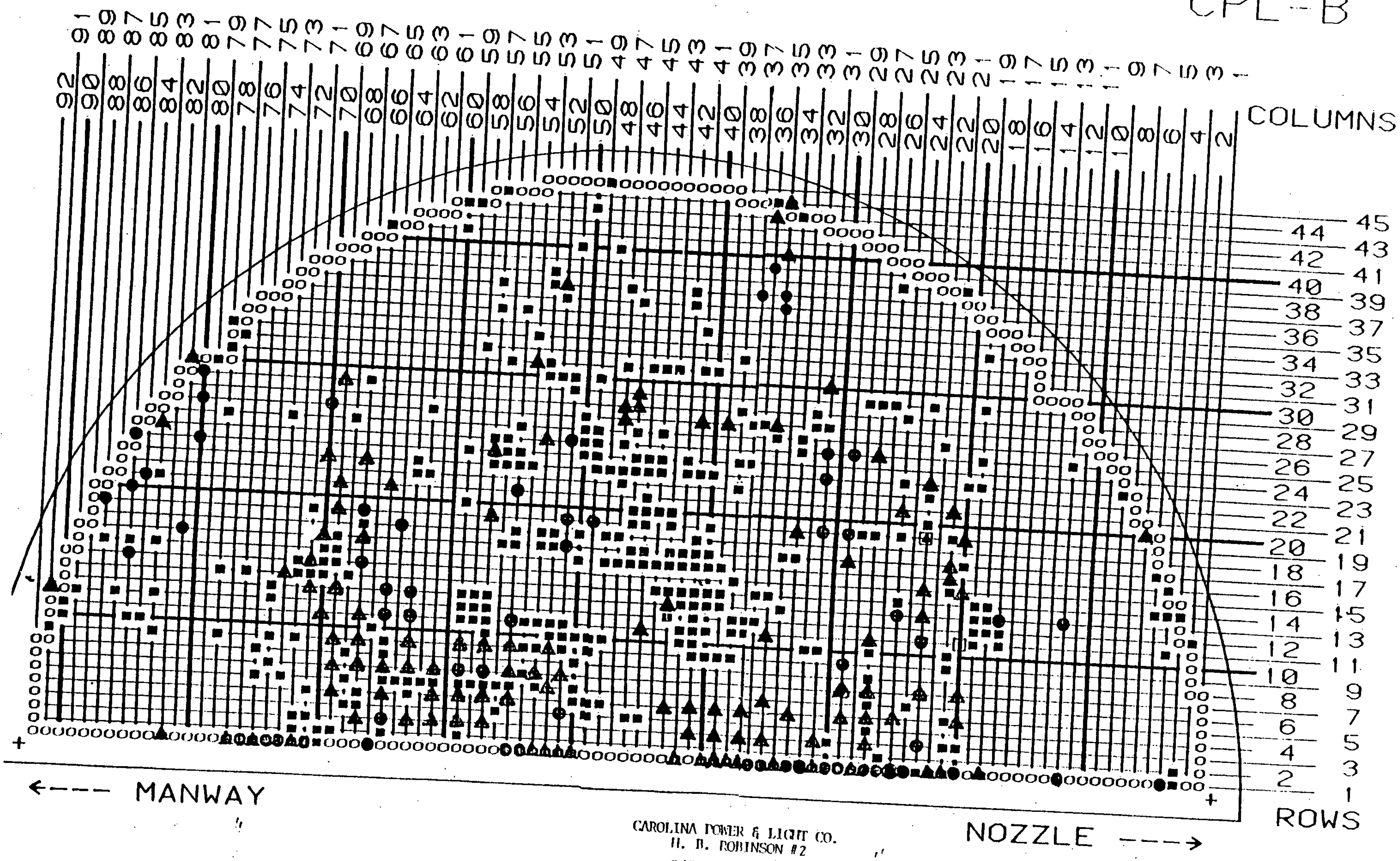
COLOR CODE
■ = U-Bend; AVB; >2 1/2" A6TSP
■ = Tube Support Plate (TSP) & ≤ 2 1/2" A6TSP

COLOR CODE
■ = Above Tubesheet (ATS)
■ = Top Tubesheet (TTS)
■ = Above Tube End (ATE)-Crevice

Figure 3.1.13

SERIES 44

CPL-B



CAROLINA POWER & LIGHT CO.
H. B. ROBINSON #2
S/G B OUTLET 8/81

GEND: O = <20% or Distorted
△ = 20-47%
□ = ≥48%

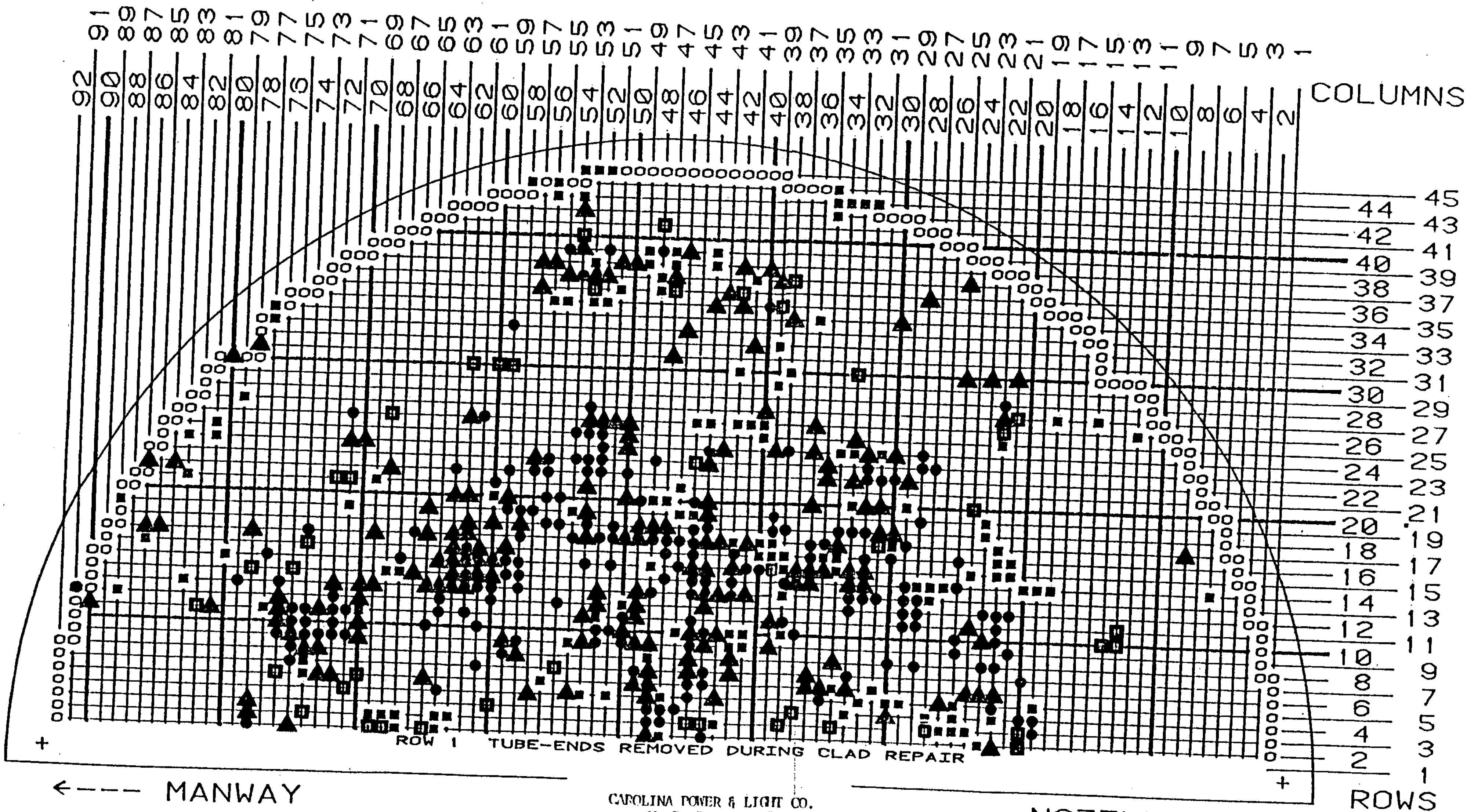
COLOR CODE
■ = U-Bend; AVB; >2 1/2" A6TSP
■ = Tube Support Plate (TSP) & ≤2 1/2" A6TSP

COLOR CODE
■ = Above Tubesheet (ATS)
■ = Top Tubesheet (TTS)
■ = Above Tube End (ATE)-Crevice

Figure 3.1.14

SERIES 44

CPL-C



CAROLINA POWER & LIGHT CO.
H. B. ROBINSON #2
S/G C - INLET 8/81

3.2 EXAMINATION OF PULLED TUBES

Two tube sections were removed from the hot leg side of S/G B for detailed non-destructive and destructive examination. The first tube examined, R36C37, was identified as a leaker reportedly containing a through-wall eddy current indication at 1" to 1 1/2" above the secondary side of the tube sheet. The second tube, R37C38, was reportedly a sound tube, free of eddy current indications. The results of the examination, which consisted of visual, radiographic, eddy current and micro-analytical non-destructive evaluation and optical and scanning electron microscopy revealed the following:

3.2.1 Leaking Tube - R36C37HL - SGB

Seven tube segments were removed extending (as shown in Figure 3.2.1) from the expanded region at the primary side of the tube sheet to the region above the first tube support plate.

1. Piece #1, containing the roll expansion, exhibited a radial split, visibly through-wall at one location, at the elevation just above the roll transition and extending essentially 360° in length. Optical metallography and SEM fractography indicated that the split was located in a band of IGA, (intergranular attack) initiating from the OD with local penetration extimated to be as deep as 90-95% of the wall. The remaining wall exhibited dimple rupture, indicative of axial mechanical overload judged to be caused by the tube removal process.

2. Piece #2, 17" in length and located between the roll transition and the secondary side of the tube sheet, exhibited a general but irregular intergranular attack initiating from the OD and ranging locally from 50% penetration near the bottom portion to 15% near the top.

3. Piece #3 spanned the top of the tube sheet and exhibited a discolored band about 1" in width, which was judged to be the portion of the tube extending above the tube sheet surface. This region was somewhat thinned and contained local pitted regions and several axial cracks, the longer about 3/8" in length. A transverse cross section identified these to be

OD initiated intergranular stress corrosion cracks, the deepest penetrating about 70% through the wall at the elevation selected. This crack is assumed to be the extension of the through wall axial crack located in the adjacent Piece #4.

4. Piece #4 contained the crack which presumably caused the primary to secondary leakage in this tube. As received, the crack was approximately 13/16" long, through-wall, and obviously deformed due to flaring of the tube end (believed to be caused by the in-situ ID cutting operation). SEM (Scanning Electron Microscopy) of the fracture faces revealed essentially total intergranular facets except at the offset, approximately at the mid-length of the crack, where a small local zone of dimple rupture was noted. This indicates that initially two shorter stress corrosion cracks existed, in tandem but offset and separated by about a 0.050" wide ligament. Subsequently, the ligament experienced continued intergranular stress corrosion cracking until the remaining sound metal over loaded, parted mechanically and permitted the two cracks to link up and form the single crack observed upon tube removal. It is not possible from the metallographic examination to unambiguously define when the link up occurred.

   Additional metallography indicated that local and superficial IGA was not associated with the major crack.

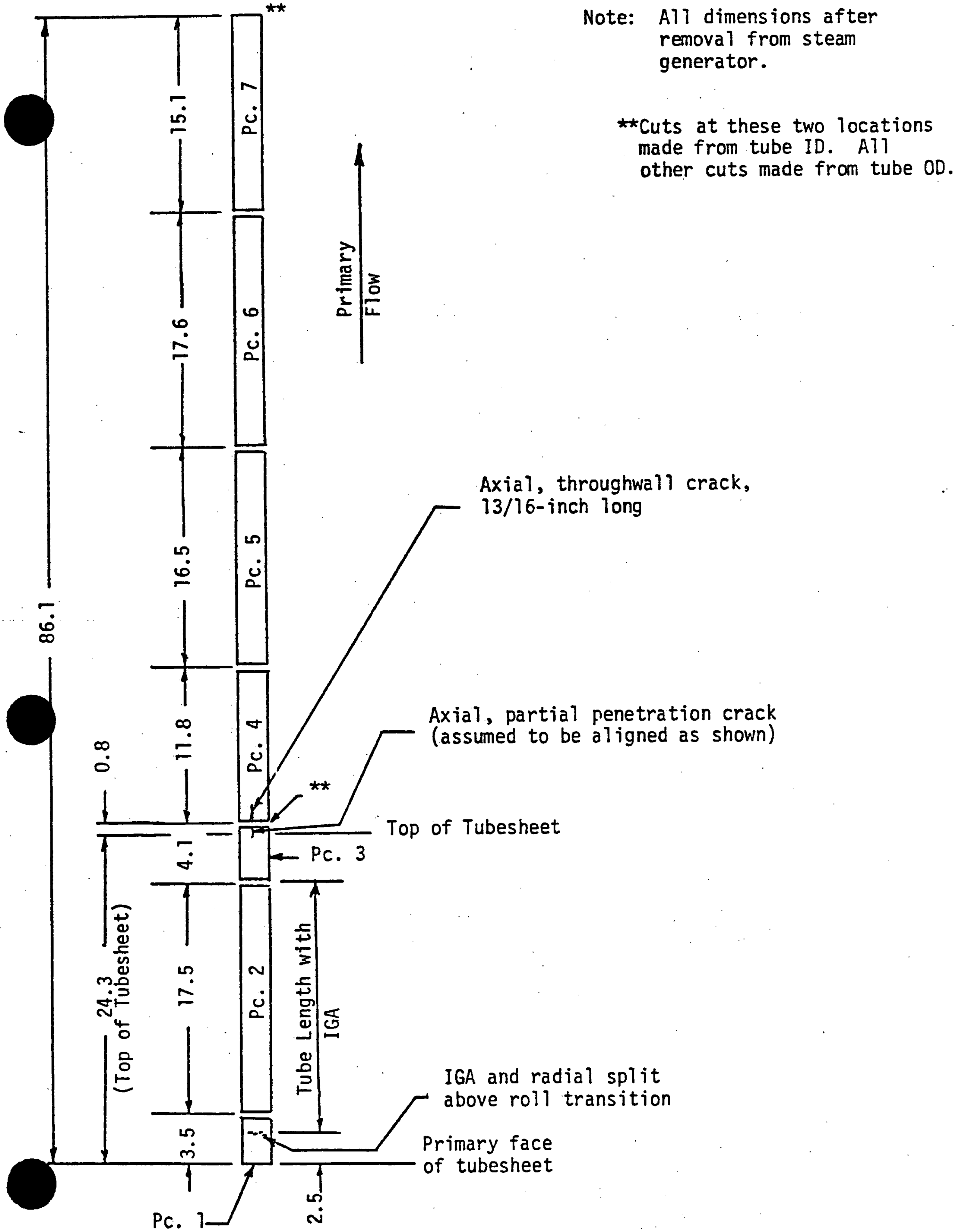
5. The remaining three segments, Pieces #5, #6, and #7, were essentially free of service-induced indications. Minor thinning was observed radiographically on Piece #7 at the first tube support plate intersection, but confirmatory metallography has not yet been completed.

3.2.2 Tube Pulled to Verify Inspection Technique - R37C38HL-SGB

Six segments of this tube were removed for examination. As shown in Figure 3.2.2, the pieces extended from the roll transition to below the first tube support plate. All pieces were judged free of indications based on double wall radiography and eddy current testing. Preliminary metallography from the tube sheet crevice region indicated no attack of any kind.

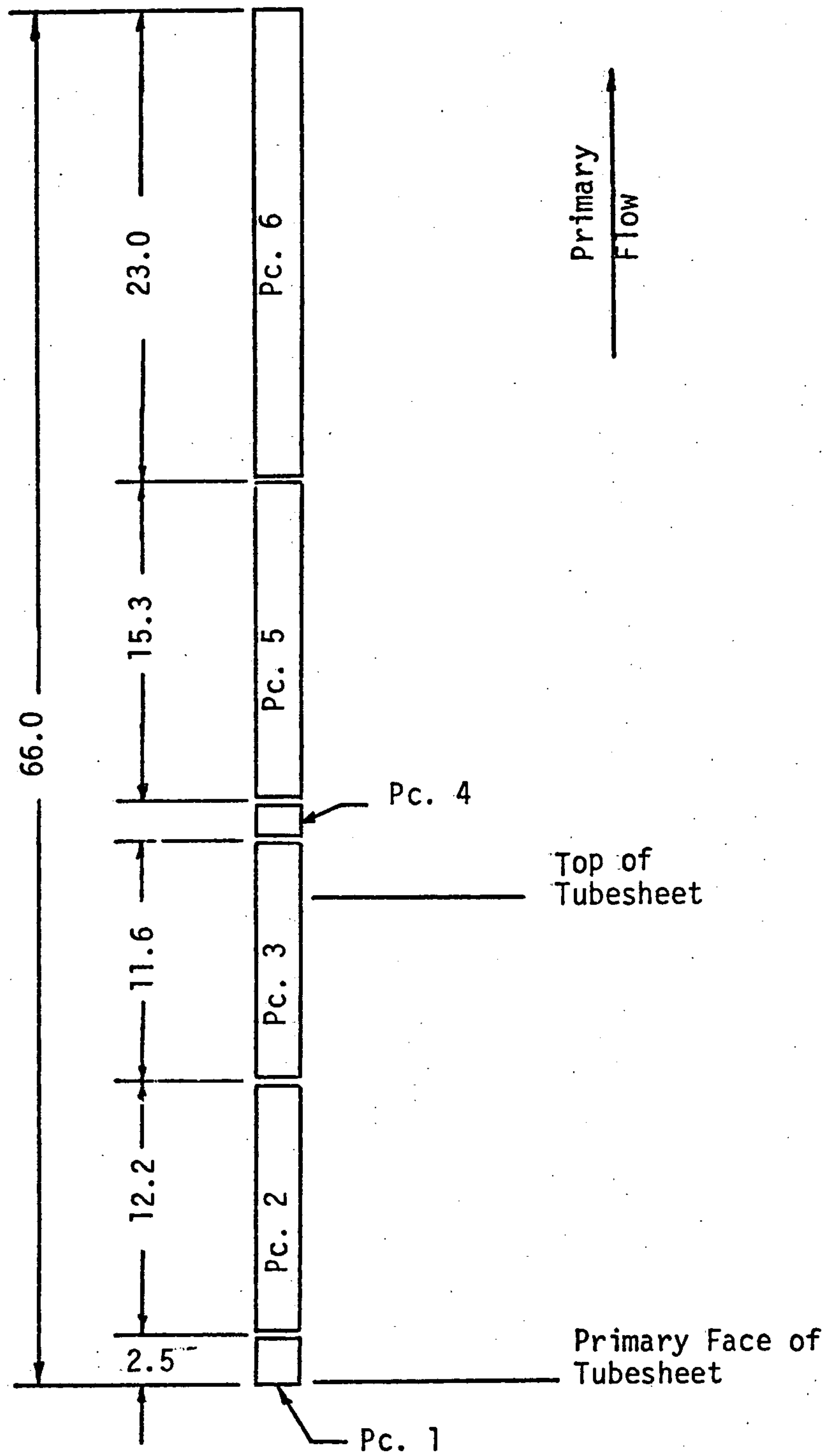
3.2.3 Discussion

The cause of the leakage and reported through-wall eddy current signals in tube R36C37 were clearly due to the axial stress corrosion crack(s) above the tube sheet surface. The intergranular nature of these cracks as well as the general IGA observed in the tube sheet crevice are consistent with previously observed metallographic evidence of caustic related attack. Although not rigorously quantifiable, laboratory tests suggest that caustic stress corrosion cracking (SCC) of Inconel 600 in the 600°F range is favored by higher stresses and higher temperature. Test data from experiments with 10% and 50% caustic concentrations show that 10% is the more aggressive environment.



SUMMARY OF EXAMINATION OF H. B. ROBINSON TUBE -- R36 C37 HOT LEG, STEAM GENERATOR B

FIGURE 3.2.1



Notes: 1. All dimensions after removal from steam generator.

2. No indications per radiographic or eddy current inspections.

SUMMARY OF EXAMINATION OF H. B. ROBINSON TUBE - R37C38 HOT LEG, STEAM GENERATOR B

FIGURE 3.2.2

4.0 CORRECTIVE ACTIONS

The results of tube evaluation via eddy current and metallographic examination revealed both the extent and the nature of the tube degradation. This degradation arises from environmental factors that govern corrosion rates existing in the micro environments of sludge piles and other flow restricted regions. The corrective actions described in the following sections address both the immediate concern of removing affected tubes from service (plugging) and additional action in terms of inducing environmental changes that minimize continued occurrences of this nature.

4.1 TUBE PLUGGING

Prior to the weekend of August 16, 1981, evaluation of the eddy current data revealed a total of 212 tubes that were identified for plugging as a result of the August, 1981 steam generator inspection. Of this total, 210 were plugged for inlet side eddy current indications exceeding 47% wall penetration or for distorted signals (11 tubes) observed below the tube sheet (crevice region). Two tubes were plugged for eddy current indications exceeding 47% in the outlet side of S/G B.

The numbers of the plugged tubes in each of the elevations (regions) within the steam generator where the pluggable indications or distorted signals were observed are tabulated in Table 4.1.1 The distributions of the tubes plugged for crevice region and tubesheet (combined above the tube sheet and top of the tube sheet) indications are plotted on tube sheet maps for each steam generator in Figures 4.1.1 to 4.1.3.

A comparison of the August, 1981 plugging totals with the total tubes plugged prior to that date is given in Table 4.1.2.

As a result of hydro test during the weekend of August 16, a leak was discovered in S/G C outlet (R5-C28). Review of eddy current data from this and the immediate surrounding tubes showed no obvious signal that could be related to the leak. Subsequently, this tube was tested with the 5 x 5 probe which revealed an indication above the top of the tube sheet. Therefore, at least 213 tubes will be plugged as a result of the eddy current and leakage observations.

TABLE 4.1.1

H. B. ROBINSON #2

TUBE PLUGGING DISTRIBUTION

AUGUST, 1981 INSPECTION

REGION	S/G A Inlet	S/G A Outlet	S/G B Inlet	S/G B Outlet	S/G C Inlet	S/G C Oulet	TOTAL
Above the Tube-sheet	28	-	73	2	39	1	143
Top of the Tube-sheet	1	-	16	0	3	-	20
Crevice	9	-	36	0	4	-	49
Tube Support Plates	0	-	1	0	0	-	1
U-Bend	0	-	0	0	0	-	0
TOTALS	38	-	126	2	46	1	213

FIGURE 4.1

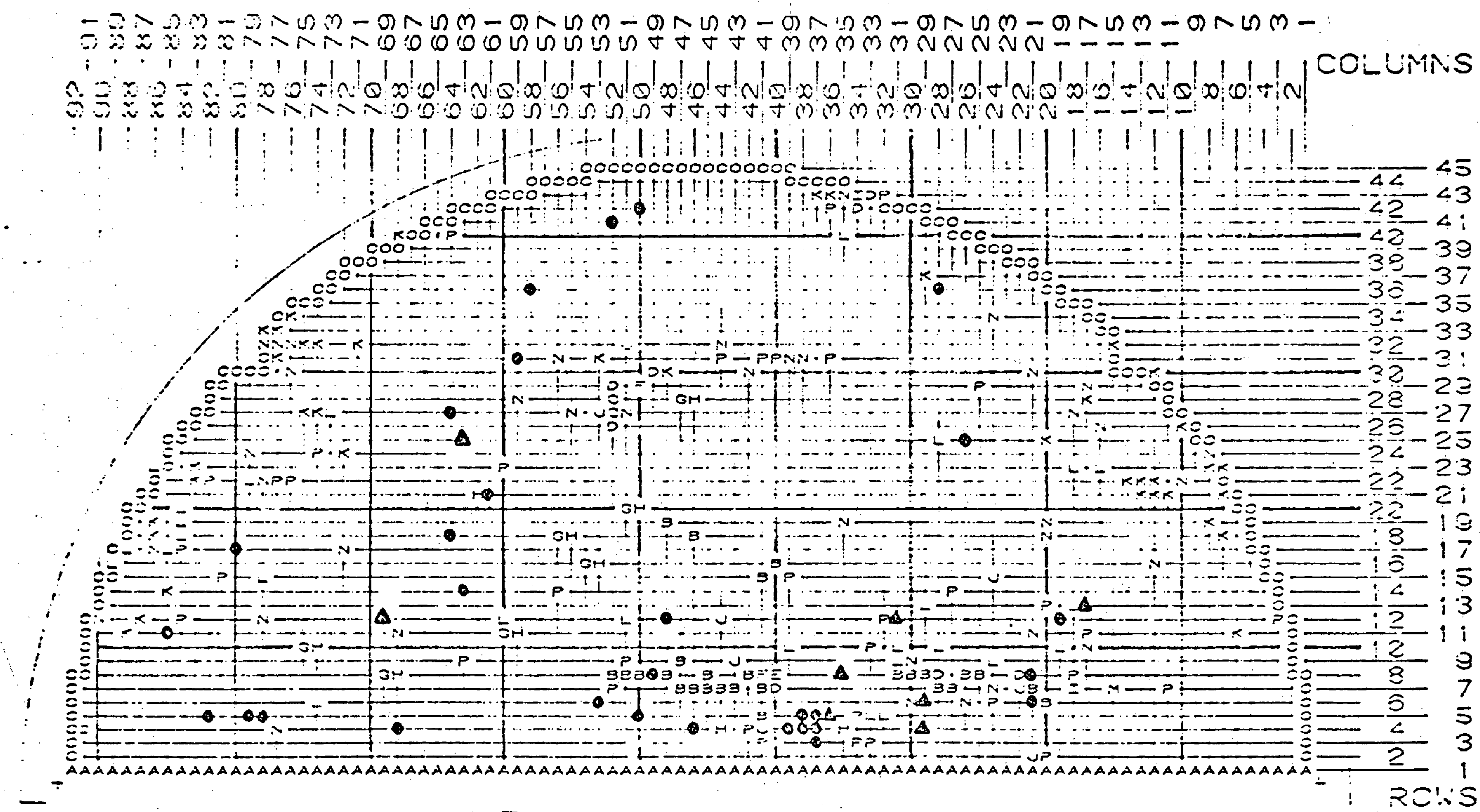
TUBES PLUGGED
H. B. ROBINSON #2
Steam Generator A

8/81 INSPECTION

A	32	TUBE ENDS REMOVED BEFORE 1/76	I	2	9/78; TUBES PLUGGED
B	27	5/72; TUBES PLUGGED	J	8	5/79; TUBES PLUGGED
C	2	5/73; TUBES PLUGGED	K	42	3/80; TUBES PLUGGED
D	3	6/74; TUBES PLUGGED	L	27	4/80; TUBES PLUGGED
E	1	4/75; TUBE PLUGGED	M	1	7/80; MECH PLUGGED
F	2	11/75; TUBES PLUGGED	N	38	9/80; MECH PLUGGED
G	7	11/76; TUBES PLUGGED	P	36	6/81; MECH PLUGGED
H	12	3/78; TUBES PLUGGED			

SERIES 44

CP_-A



⊕ = TUBESHEET REGION (ATS & TTS)

Δ : CREVICE REGION

TUBES PLUGGED
H. B. ROBINSON #2
Steam Generator B
8/81 INSPECTION

FIGURE 4.1.2

A	4	5/72; TUBES PLUGGED
B	22	6/74; TUBES PLUGGED
C	2	4/75; TUBES PLUGGED
D	3	11/75; TUBES PLUGGED
E	3	11/76; TUBES PLUGGED
F	3	3/78; TUBES PLUGGED
G	2	5/79; TUBES PLUGGED
H	1	4/80; M/P H/L, E/P C/L
I	85	4/80; TUBES PLUGGED
J	53	9/80; MECH PLUGGED
K	112	6/81 MECH PLUGGED
L	2	E/P, DATE UNKNOWN

SERIES 44

CPL-B

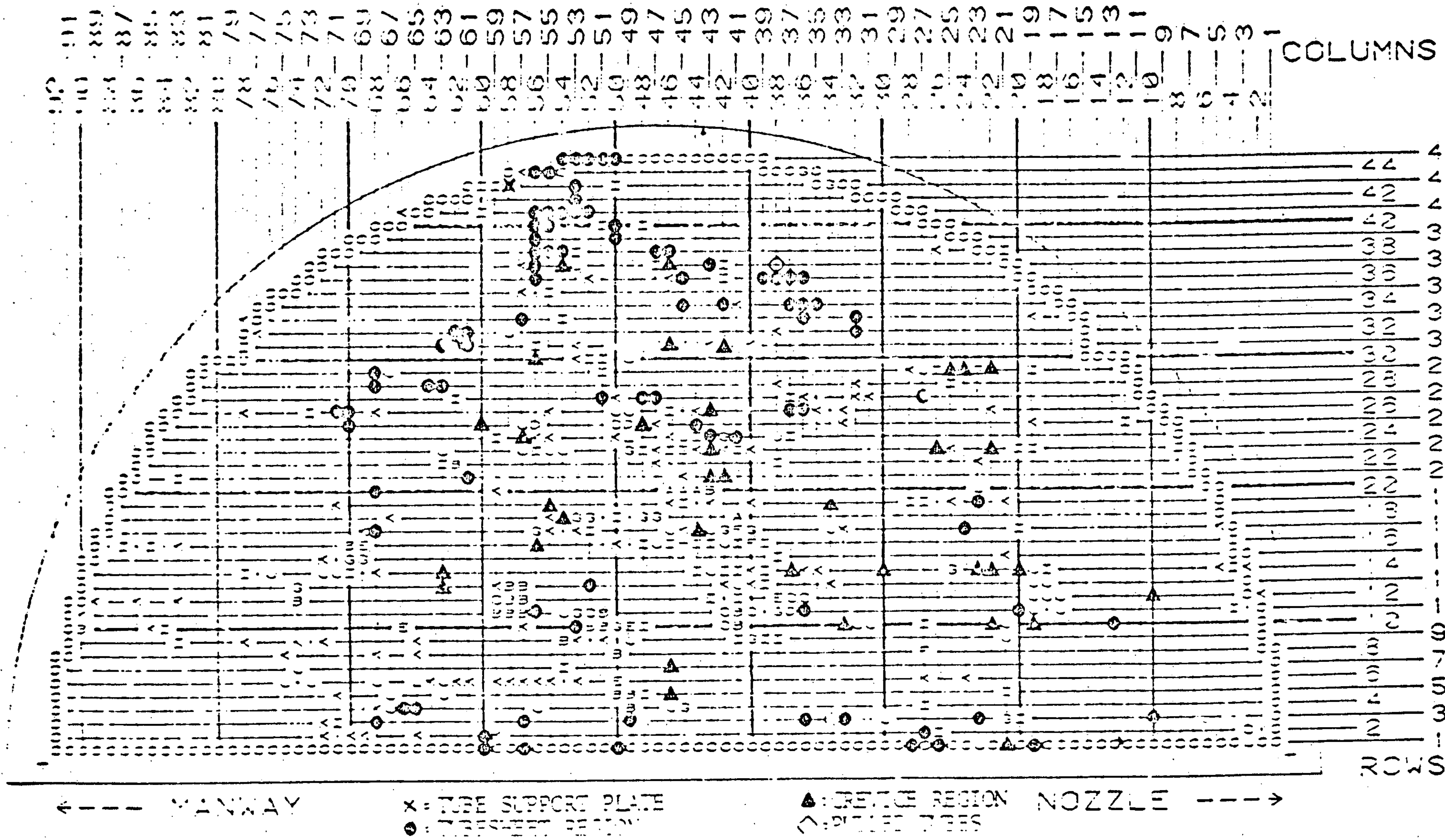


FIGURE 4.1.3

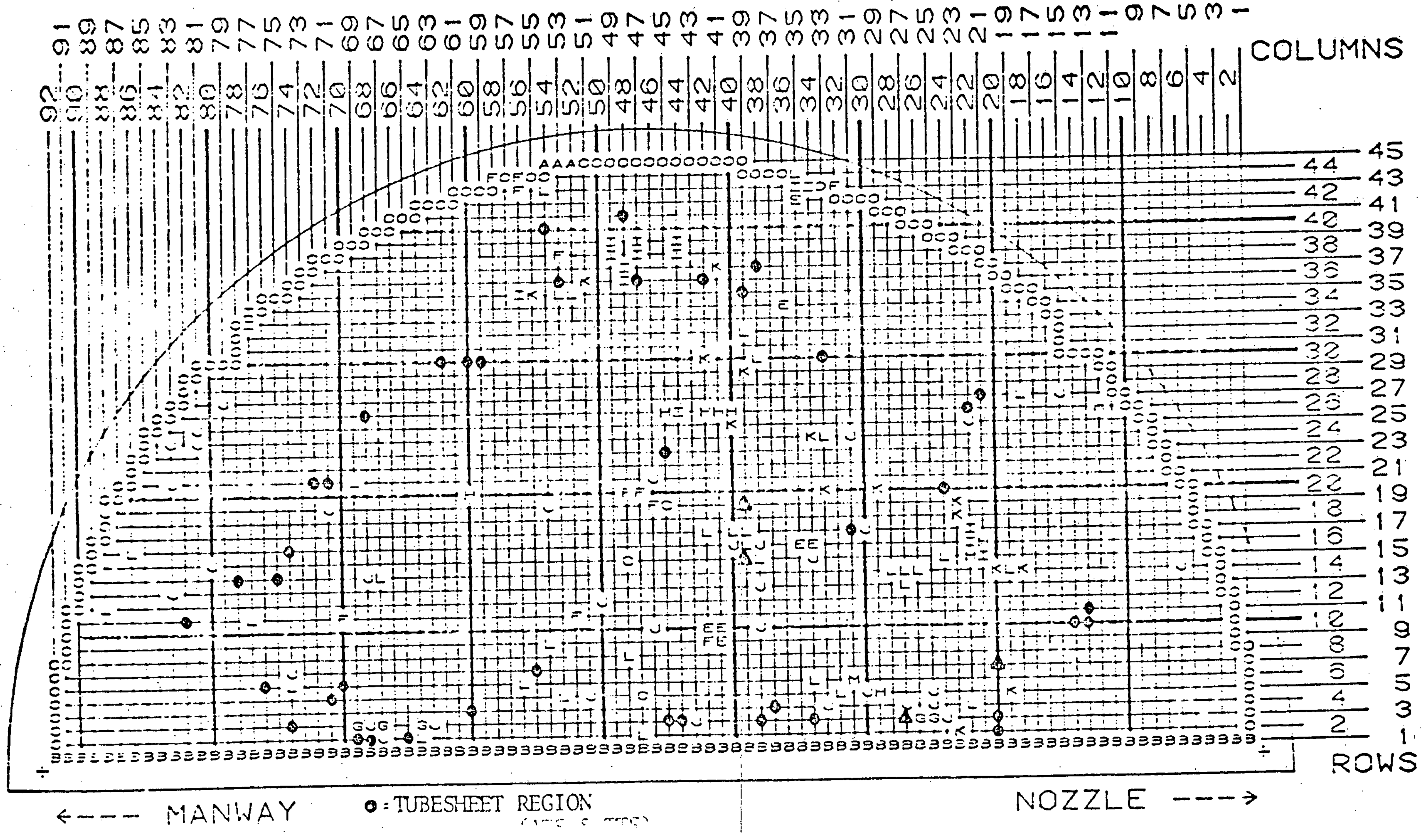
TUBES PLUGGED
H. B. ROBINSON #2
STEAM GENERATOR C

8/81 INSPECTION

SERIES 44

CPL-C

A	3	SHOP WELD
B	92	TUBE ENDS REMOVED, BEFORE 1/76
C	2	5/72; TUBES PLUGGED
D	1	11/73; TUBE PLUGGED
E	7	6/74; TUBES PLUGGED
F	11	11/75; TUBES PLUGGED
G	6	3/78; TUBES PLUGGED
H	9	5/79; TUBES PLUGGED
I	17	3/80; TUBES PLUGGED
J	36	4/80; TUBES PLUGGED
K	15	9/80; MECH PLUGGED
L	34	6/81; MECH PLUGGED
M	1	6/79; TUBE E/P



4.2 REMEDIAL ACTIONS TO MODITY THE OPERATIONAL ENVIRONMENT

In instances where secondary side corrosion of steam generator tubing has been observed, it has generally been localized to crevice or sludge pile regions. In these areas the normally high heat flux from the free surface of the tube becomes impaired due to the buildup of deposits which restrict free access of the water to the tube surface. The deposits are somewhat porous, however, and the water which permeated into the deposits is eventually boiled and leaves the flow restricted region as steam. In the process of this conversion the dissolved solids present in the water remain in the porous deposits and increase in concentration to limits that depend on the physical chemical characteristics of the dissolved species as well as the thermal and hydraulic conditions present in the local region. The concentrating chemicals may by capable of causing corrosion of steam generator materials or they may interact with other sludge components to form environments that subsequently may affect the steam generator materials.

In the case of phosphate chemistry control, the added phosphate has the benefit of acting as a buffer and thereby moderates the chemical environment by mitigating against rapid changes in the bulk water pH. It has been observed, however, that phosphates can also react with secondary side corrosion products, such as magnetite (Fe_3O_4), to produce hard sludge. One equation, which is only intended to be illustrative of this process, is shown as (1). The solid iron phosphate reaction product

$$3Na_3PO_4 + Fe_3O_4 + 3\ H_2O \rightarrow 3\ NaFePO_4 + 6NaOH + \frac{1}{2}O_2 \qquad (1)$$

is suspected to consolidate the sludge and harbor additional concentrations of other species in the proximity of the tube surface.

In steam generators that are experiencing corrosion in sludge pile regions a two fold action plan involving removal of the non-consolidated sludge followed

by flushing to reduce the inventory of soluble species in the remaining sludge pile appears to be prudent. Past experience at H. B. Robinson indicates that sludge lancing appears to be effective. The techniques being used at H. B. Robinson Unit 2 to accomplish these goals are sludge lancing and crevice/sludge flushing.

4.2.1 Sludge Lancing

Sludge lancing removes solid steam generator deposits by the use of high velocity water jets that are directed along the surface of the tube sheet and between the columns of tubes. The deposits are swept out of the tube bundle and subsequently removed from the steam generator by entrainment in the process water.

Sludge lancing of H. B. Robinson Unit 2 steam generators has already been done as part of the program to improve the local steam generator environment. This lancing operation appeared to be quite effective in removing loose sludge deposits.

4.2.2 Crevice/Sludge Flushes

A technique to remove additional potentially aggressive chemicals remaining after the sludge lancing operation is Crevice/Sludge Flushing. This process involves depressurization of the steam generators at a temperature of approximately 275-350° F. The depressurization promotes boiling in the crevice/sludge pile which tends to flush additional contaminants from these regions.

4.3 ON-LINE ACTIONS TO POTENTIALLY MINIMIZE TUBE DEGRADATION

The remedial actions described previously should be of potential benefit in reducing the severity of the chemical environment present in the vicinity of the tube sheet sludge pile. With the presence of hard sludge, however, contaminant removal is not expected to be completely effective. Under these circumstances it is possible to further reduce the corrosion rates by operating under reduced power conditions. The probable benefits of reduced

power conditions are achieved through a reduction in the local temperatures occurring in a flow restricted area. The special case of mixed power operation with the majority of operating time at reduced power and intermittant periods of high power operation is discussed in section 4.3.2.

4.3.1 Benefits of Reduced Power Operation

The potential benefit of reduced power operation is expected to be a reduction in the corrosion rate due to the reduction in temperature. The approximate temperature changes for reduced operation from 95%-50% are shown in Table 4.3.1.

Figure 4.3.1 represents the approximate relative corrosion rate of mill annealed I-600 in a 10% NaOH environment as a function of power level under the present operational T_{AVG} program at H. B. Robinson Unit 2. (The original corrosion rate data were developed as a function of temperature and this has been related to power levels by equating values for T_{HOT} to the original corrosion rate vs temperature curve). The points A&B indicated on the curve for the example of 95% and 50% power represent a reduction of approximately a factor of 5 in the corrosion rate. A reduction in rate, coupled with the anticipated benefits of the sludge lancing and flushing, should reduce the rate of tube degradation occurring in the sludge pile region. Therefore CP&L intends to operate Robinson-2 at an approximate power level equivalent to 50% or 576°F (T_{HOT}) for the remainder of this operating cycle.

4.3.2 Calculation of Equivalent Power Operation (50% or 576°F)

The premise for this computational procedure is as follows:

1. Significant corrosion occurred within 48 days at high power operation. If corrective actions were not being taken to modify the environment, it would be reasonable to expect that some means of evaluating bundle integrity be performed in one half of that time (i.e. 24 days at the 95% power level).

2. The corrosion rate data of Figure 4.3.1 illustrates that a reduction to 50% power should gain an approximate 4.7 fold benefit in reduced corrosion rate to give an effective 112 days (4.7 x 24 days from 1. above) at 50% power.

3. Further modifications to the environment by removal of sludge and crevice/sludge pile flushing should have the potential of further benefiting the performance; a factor of two is judged conservative for this benefit. The result is (2x112) 224 days of 50% power operation. After this the unit should undergo eddy current analysis to evaluate the overall effect of the combined ameliorative actions. Intermittant evaluation of bundle integrity will be performed at intervals as described in section 5.1.1.

Based on this premise the formula for calculating the period of equivalent 50% power operation is shown below.

$$t_p \times C_A = t_o \qquad (1)$$

t_p - time at a given power level in hours

C_A = corrosion allowance at that power level (see figure 4.3.3)

t_o = equivalent operational time at 50% power

As an example consider that a days operation followed the load variation shown in figure 4.3.2. For this day 16 hours were at 50%, 4 hours at 95% and 4

hours at 70% power. According to the formula of equation (1) and the corrosion allowance from the normalized curve Figure 4.3.3, the following effective 50% power operation has been incurred. (16 hrs x 1) + (4 hrs x 4.7) + (4 hrs x 2.2) = 43.6 hours. Thus, this one operational day utilized a total of approximately 44 hours of equivalent operation at 50% power because of load variations.

10% NaOH

I-600 MA MATERIAL

BASED ON T_H CALCULATIONS FOR CPL WITH 15% TUBE PLUGGING AND PRESENT T_{AVE} PROGRAM. (ORIGINAL CORROSION DATA FROM ISOTHERMAL AUTOCLAVE EXPOSURES.)

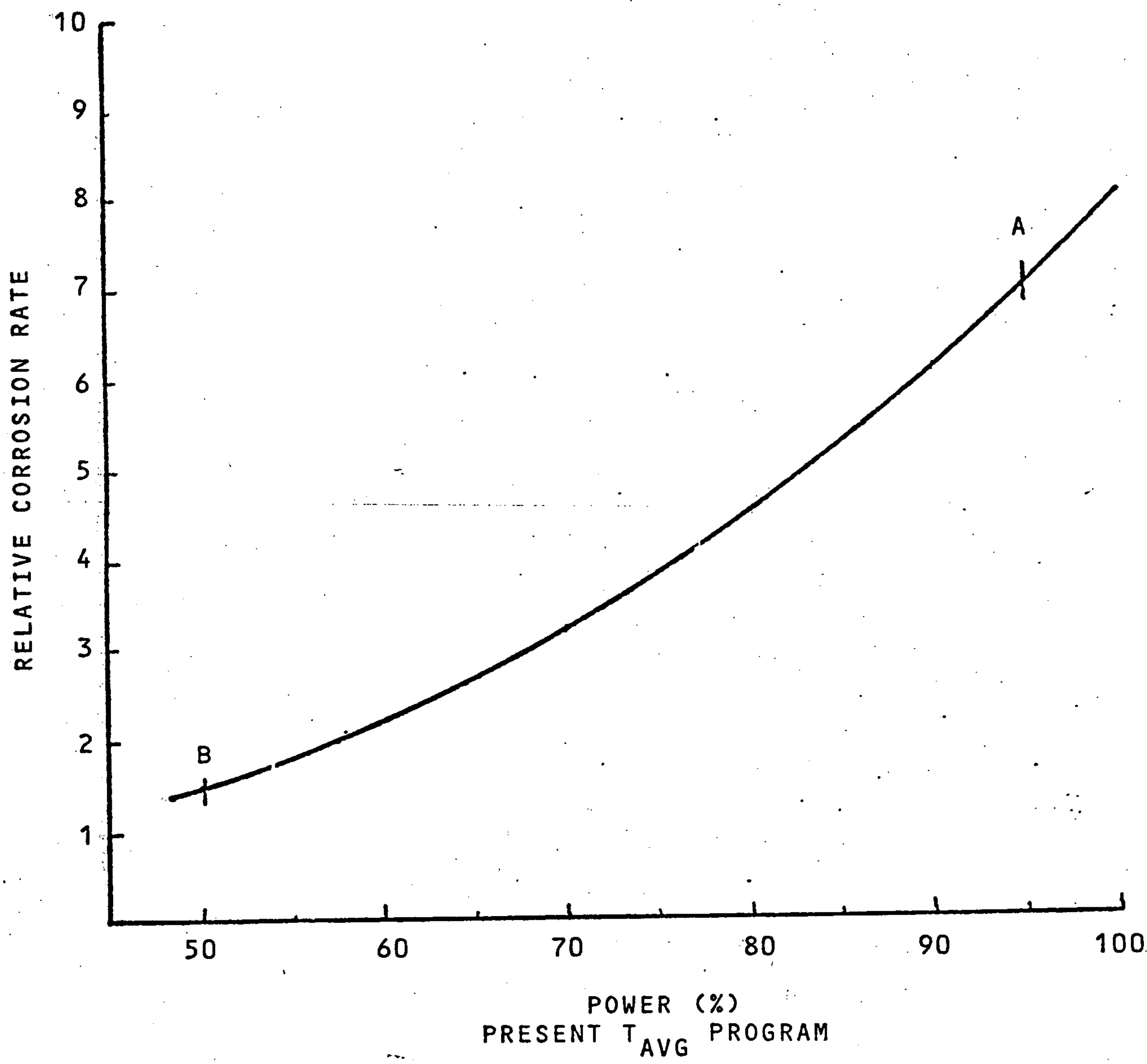


FIGURE 4.3.1

RELATIVE TUBE CORROSION RATE AS A FUNCTION OF POWER LEVEL WITH AN ASSUMED ENVIRONMENT OF 10% NaOH

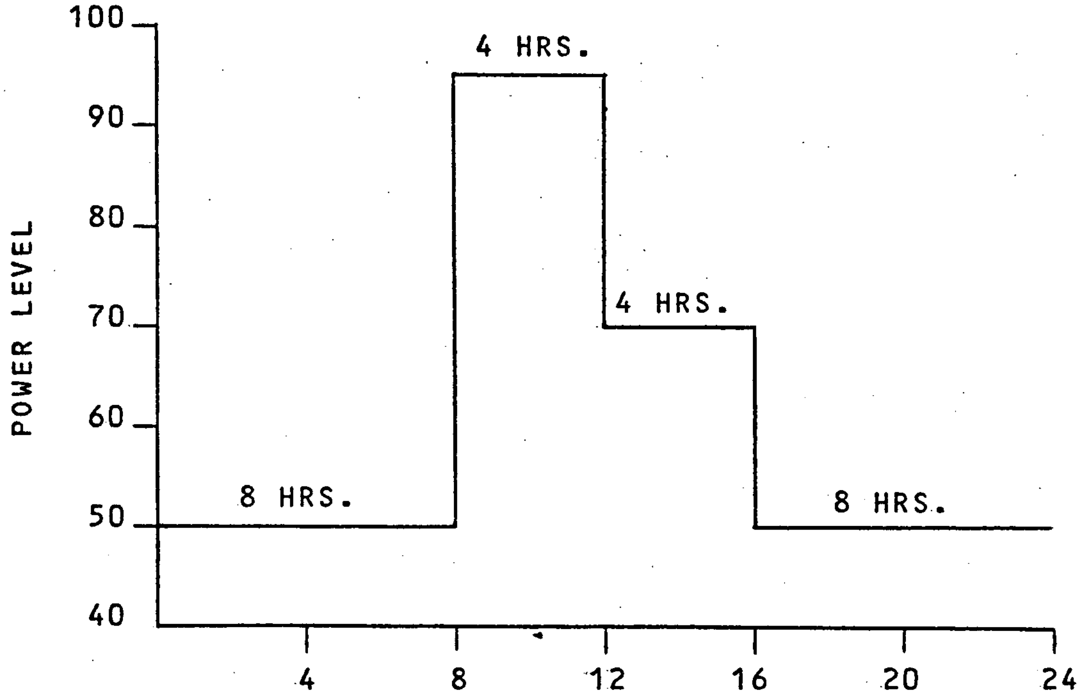


FIGURE 4.3.2

EXAMPLE OF POWER LEVEL VARIATION USED
IN COMPUTATION OF EFFECTIVE 50% POWER DAYS

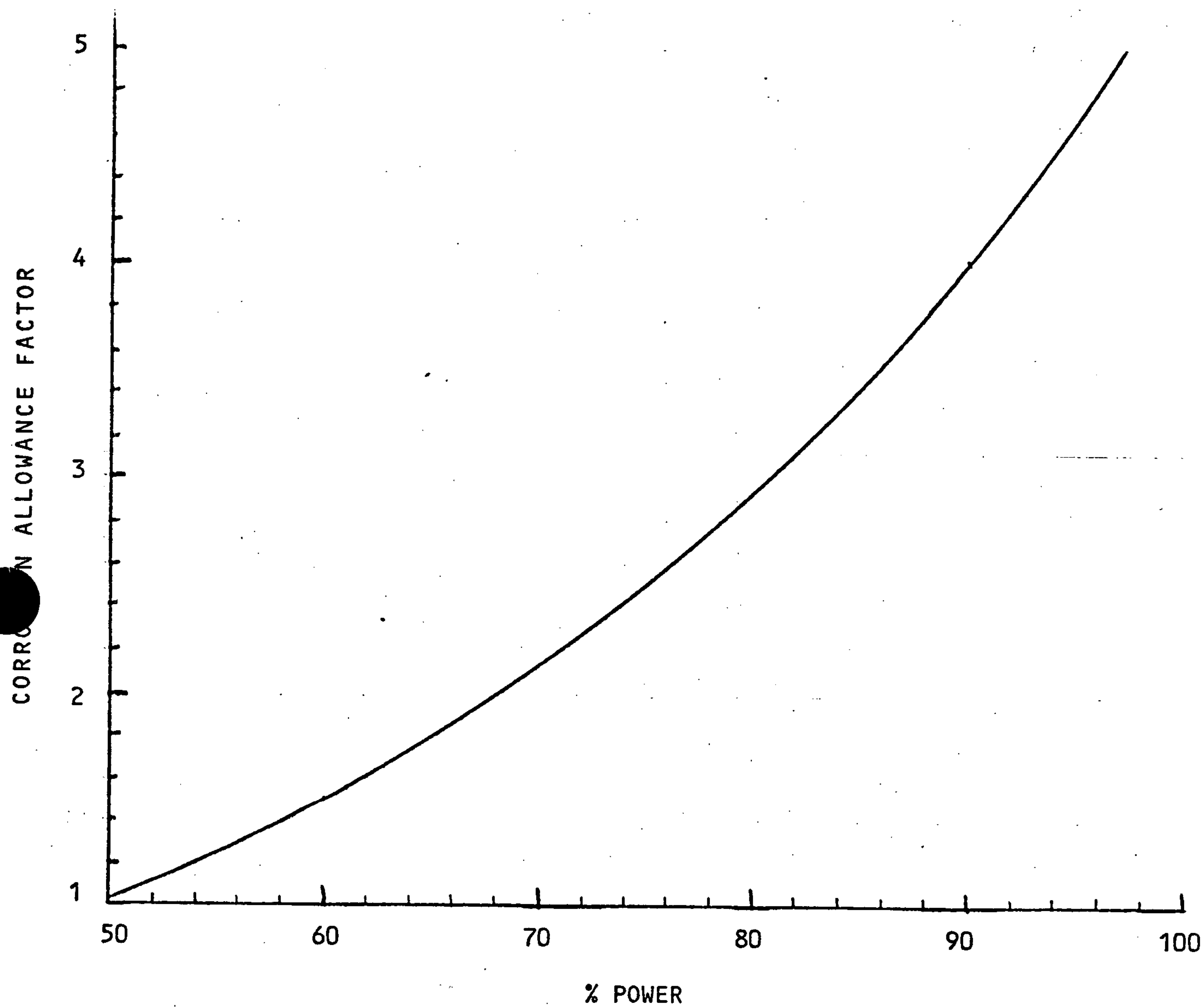


FIGURE 4.3.3

CORROSION ALLOWANCE FACTOR AS A FUNCTION OF POWER
FOR PRESENT T_{AVG} CONTROL PROGRAM OF H. B. ROBINSON UNIT 2

5.0 SAFETY EVALUATION

5.1 DEGRADATION EVALUATION

5.1.1 Through Wall Degradations

The leaking tube pulled from H. B. Robinson S/G B was found to contain a axial crack, 13/16 inches long above the top of the tube sheet. This tube was one of two leaking tubes in S/G B which, at the time the plant was shutdown, had a combined leak rate of approximately 0.3 gpm at normal operating primary-to-secondary differential. This leak rate is below the technical specification limit for required plant shutdown.

The burst pressure and expected leakage rate at normal operating conditions were determined for the 13/16 crack length. Data for determining these values was presented in "CPL Steam Generator Tube Plugging Criteria Caluations" (WTD-SM-77- 058). Figure 3-1 of the report (attached as Figure 5.1.1) shows curves of leak rate versus pressure for various crack lengths and temperatures. Figure B-1 of the report (attached as Figure 5.1.2) shows a curve of crack length to room temperature burst pressure. Burst pressure at operating temperature is related to room temperature burst pressure via the ratio of material ultimate strengths at room temperature and operating temperature.

Examination of the leak rate curve for the 13/16" (.8125) crack length (using .8"), operating temperature (using 540°F), and normal operating pressure differential (1500 psi), yields a predicted leak rate of 3.6 gpm. The fact that two tubes, one with a 13/16" crack length, leaked at approximately .3 gpm is explained by the presence of sludge at the OD of the tubes. The sludge adds a resistance that will reduce the actual leak rate below the predicted value based on testing of free standing tubes. There has been no testing to quantify this effect. For this one case, the leakage was apparently reduced by more than a factor of 12.

From the lower tolerance limit burst pressure curve, the burst (fishmouth) pressure for a 13/16" crack is 2135 psi at room temperature and 2060 psi at 600°F. The lower tolerance limit burst pressure is determined statistically from the test data such that the confidence is 95% that 95% of the tube population will have a greater burst pressure for a specified crack length. Comparing the 2060 psi burst pressure with the normal operating and accident differentials, 1500 psi and 2575 psi respectively, the tube with a 13/16" crack would not be expected to fishmouth during normal plant operation; however, it is indeterminate whether or not it would fish-mouth during the steam line break accident. Using a best fit curve for the burst pressure data, the burst pressure for the 13/16" crack is 2512 psi at 600°F.

The leaking tube also contained a through wall, 360°, radial split just above the roll transition. The split was located in a base of IGA. This type of degradation in the tubesheet is not a safety concern, only an operating concern. If the tube should leak in this area the leak is restricted by the tubesheet annulus. This annulus is sufficiently small to restrict tube leakage even if the tube should suffer a complete 360° circumferential rupture.

5.1.2 Part Wall Degradations

This section addresses the possibility of pre-existing part through wall degradations penetrating the wall as a result of the steam line break accident differential. In this case the tubes have sufficient wall thickness to sustain the normal operating pressure differential. Experience with the propagation of part wall intergranular cracks in Inconel 600 has been that there is an aspect ratio of length (on the initiating surface) to depth of penetration through the wall (Figure 5.1.3). The aspect ratio has been observed to vary between 2 and 5. The most conservative

assumption is that the aspect ratio is five. For this discussion let us conservatively assume an aspect ratio of 6. For a 0.050 inch wall thickness (the nominal tube wall dimension of the Robinson 44 Series Steam Generator) the crack would proceed through the wall when the length dimension on the initiating surface reached 0.30 inches.

Thus, it is conservatively assumed that under the primary to secondary pressures associated with a steam line break, the part wall defect will suddenly become a 0.30 inch through wall crack (Figure 5.1.4) i.e., the crack assumes the same dimensions on both inner and outer surfaces of the tube wall - though this is not the observed mode of failure. This crack configuration would be stable, because the length is significantly less than the "critical crack" length (the length at which the defect becomes unstable for a given pressure differential) for the steam line break accident. Note from Figure 5.4.2 that a 100% wall crack of 0.3 inches length will not fail below 5000 psid. Therefore, part wall cracks which are postulated to propagate through the wall following a steam line break accident would not result in a failed tube, but would leak at the low rate associated with a 0.30 inch crack.

Laboratory tests of tubes with a tight 0.30 inch length crack show that no plastic deformation will occur. Additionally, the flow characteristics of these cracks were below the lower sensitivity of the flow measuring device (approximately 0.05 gpm) at a pressure differential of 2000 psi. Thus it will be conservatively assumed that any additional cracks of this type have a leakage rate of 0.05 gpm irrespective of pressure differential for all differentials below 2000 psi. Further testing showed that a .3" fatigue crack did not develop a detectable leak rate up to a 2700 psi differential.

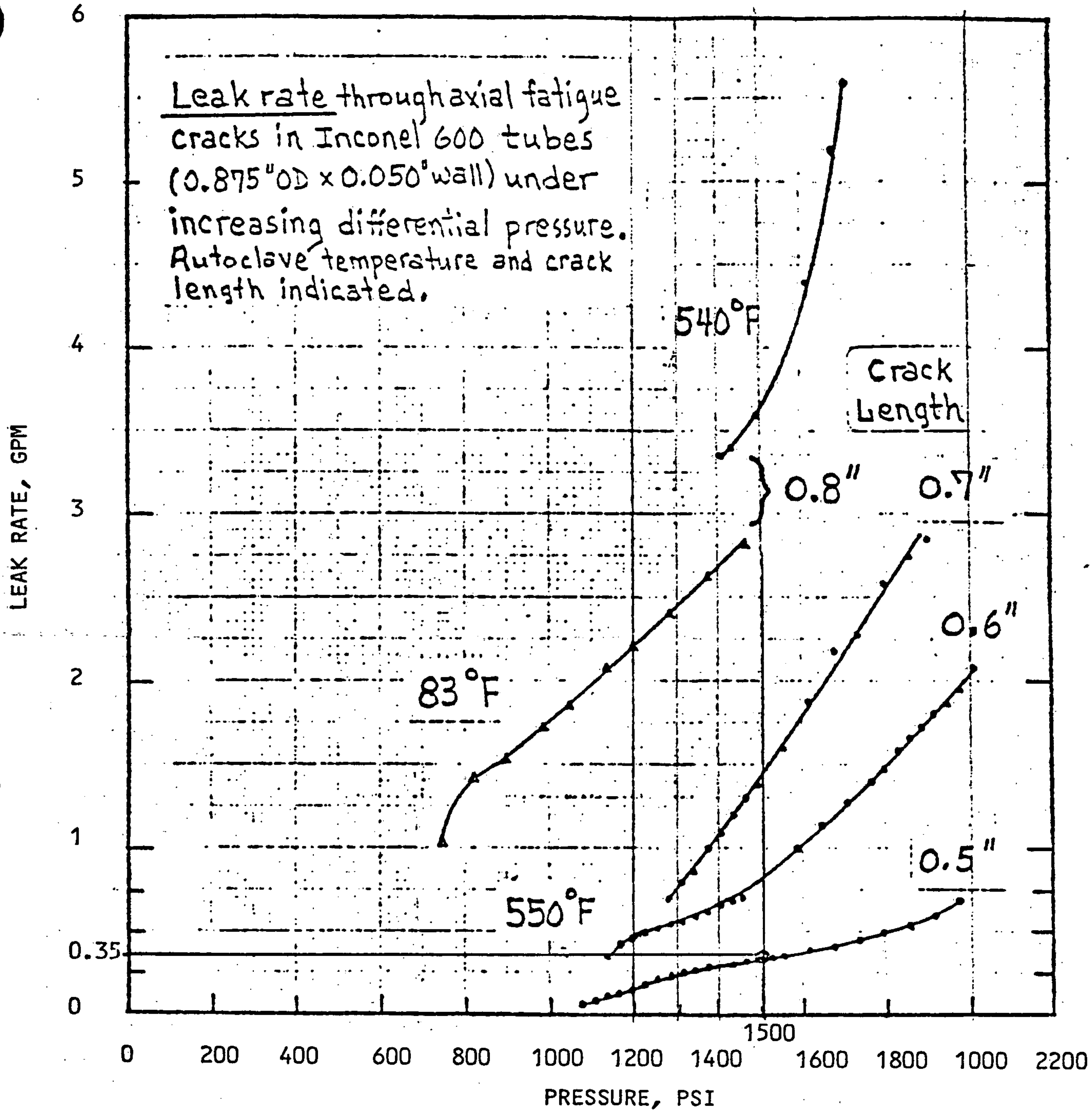

Leak rate through axial fatigue cracks in Inconel 600 tubes (0.875"OD x 0.050"wall) under increasing differential pressure. Autoclave temperature and crack length indicated.
540°F
Crack Length
0.8"
0.7"
0.6"
0.5"
83°F
550°F
LEAK RATE, GPM
PRESSURE, PSI
6
5
4
3
2
1
0.35
0
0
200
400
600
800
1000
1200
1400
1500
1600
1800
1000
2200

FIGURE 5.1.1

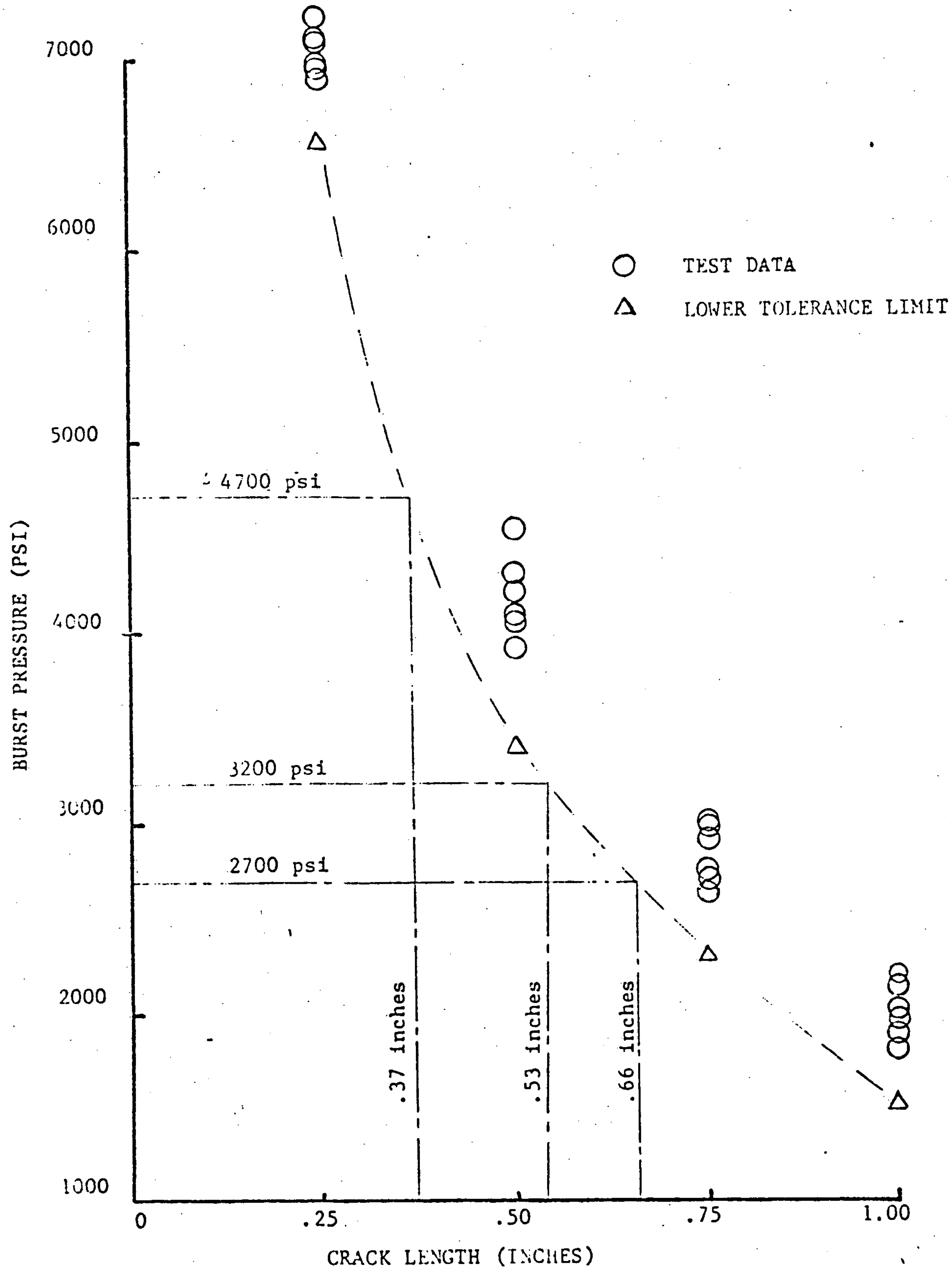
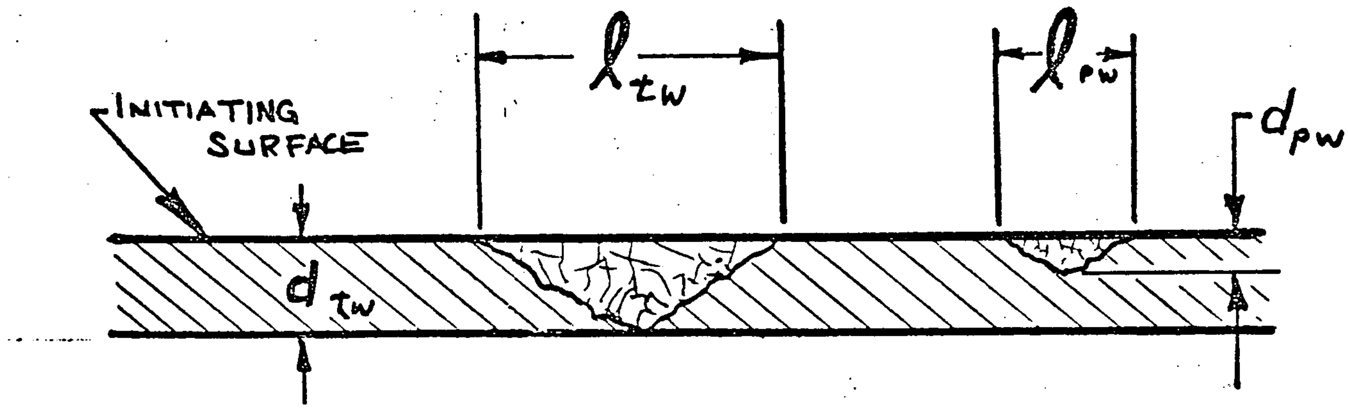


FIGURE 5.1.2

BURST PRESSURE TEST DATA



THROUGH
WALL DEFECT

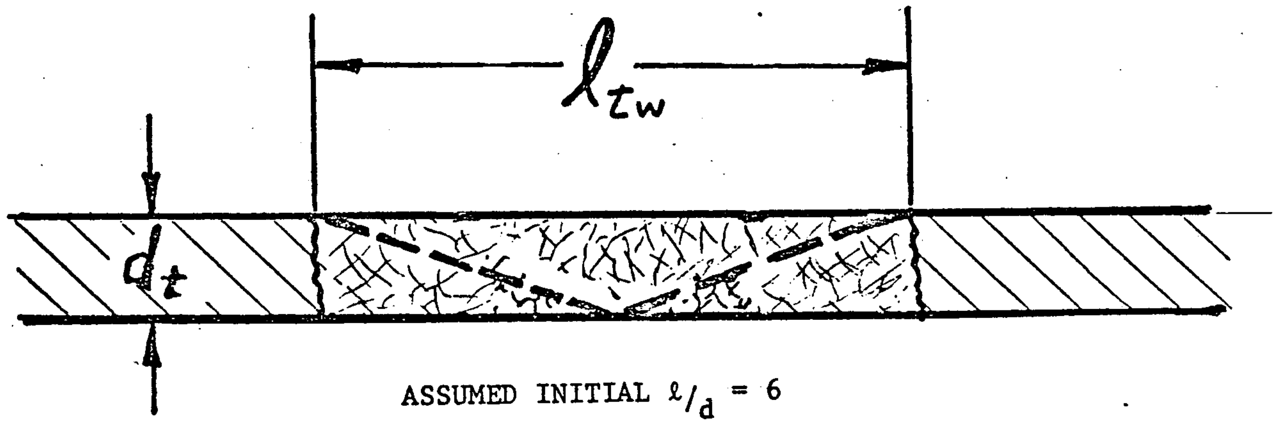
PART WALL
DEFECT

THROUGH WALL ASPECT RATIO = $\frac{\ell_{TW}}{d_{TW}}$,   PART WALL ASPECT RATIO = $\frac{\ell_{PW}}{d_{PW}}$

AT BREAK THROUGH; $\ell/_{d} \simeq 4$

FIGURE 5.1.3

CRACK ASPECT RATIO



ASSUMED INITIAL $\ell/_d = 6$

$d = .050$

$\ell = 6\ (d)$

$\ell = 6\ (.050)$

$\ell = 0.3$

FIGURE 5.1.4

ASSUMED FAILURE GEOMETRY

5.2 TUBE BUNDLE INTEGRITY UNDER PRESENT CONDITIONS

The previous sections have detailed the results of the eddy current inspection and identified the number and locations of the tubes that have been plugged. Examination of the leaking tube pulled from steam generator B has shown that the mode of tube degradation is stress corrosion cracking that is suspected to arise from a caustic environment. Supplement of the standard eddy current technique using an advanced "5x5" probe, and an additional pull of a tube without detectable degradations has verified the results observed with the standard bobbin probe.

In addition to plugging of the affected tubes the local environment has been improved by the sludge lancing and planned, flushing and neutralization techniques. Additional benefit is expected from the planned operation at the 50% power level. The rationale and computational procedures for calculating equivalent 50% operational time periods have also been developed and presented.

The combination of actions, coupled with good operational practice related to condenser and air in leakage, should allow the unit to operate for the indicated ~ 220 equivalent 50% power days.

Verification of tube bundle integrity will be achieved by subjecting the bundle to a primary to secondary pressure test. The plugging of the identified pluggable tubes, the validation of the ECT technique by the tube pulls and the bundle pressure tests demonstrate the integrity of the tube bundle in its present condition.

5.3 PERIODIC TUBE BUNDLE INTEGRITY CHECK

After 30 Effective Full Power days (EFPD) of operation the tube bundle integrity will be verified by a primary side pressure test. An eddy current test program will then be implemented during the refueling outage to quantitatively verify the condition of the tube bundle.

5.4 LEAKAGE SURVEILLANCE PROGRAM

During the remainder of the present cycle 8 operations, the following steam generator tube leakage criteria will be in effect. Specifically, the plant will be shutdown if the verified primary to secondary leakage in one steam generator exceeds any of the following:

1. A sudden increase of 0.1 gallon per minute (gpm) if the total leakage rate in that steam generator exceeds 0.2 gpm.

2. If the leakage rate in that steam generator exceeds 0.2 and an upward trend in leakage rate in excess of 0.02 gpm per day is verified. This trend will be established using at least five valid consecutive daily samples.

6.0 SAFETY EVALUATION SUMMARY

The integrity of the tube bundle has been established by plugging all leaking tubes and tubes with ECT indications greater than the plugging criteria. The ECT methods have been verified by the tube removal examinations. The bundle integrity has been demonstrated with the pressure test.

The environment in the steam generator has been modified by the sludge lancing and the planned crevice/sludge flushing procedure.

Laboratory data shows that corrosion rates are sensitive to temperature. The plant will be operated at a reduced power level equivalent to that which would result in the benefit of operating at 50% power as described in section 4.3.3. This is estimated to reduce the corrosion rate by a factor of 4.7. In addition to the reduction in operating temperature, bundle integrity will be verified by a primary side pressure test after 30 EFPD. Restrictions on present leakage limits and leak rate changes will be implemented.

With the actions taken to improve the steam generator environment, the reduced operating conditions, the pressure testing and tighter leakage criteria it is assured that continued operation of the plant does not pose a risk to the public health & safety.

ATTACHMENT C

"Steam Generator Inspection Report
for
May-June 1981 Steam Generator Outage"

ATTACHMENT C

H. B. ROBINSON STEAM ELECTRIC PLANT

UNIT NO. 2

STEAM GENERATOR INSPECTION REPORT

FOR

MAY-JUNE 1981 STEAM GENERATOR OUTAGE

I. Introduction:

On May 16, 1981, the H. B. Robinson Plant Unit No. 2 was shutdown for a mid-cycle Steam Generator (S/G) inspection. The purpose of this inspection was to establish tube wall corrosion rates in regions of the tube bundle where corrosion rate concerns have been identified by recent inspections. This inspection was not intended or required to be governed by Technical Specification requirements.

II. Steam Generator Inspection:

a. Inspection Technique

The inspections were performed using multi-frequency eddy current equipment. The inspection frequencies utilized were 400 KHz differential, 200 KHz differential, 10 KHz differential and 100 KHz absolute. To aid in the detection of tube wall degradation, 400 KHz - 200 KHz signal mixes were utilized.

b. Inspection Scope

The initial inspection sample was limited to a selected number of tubes from "A" S/G. The sample consisted of the following:

1. All U-bend indications $\geq$ 30% (65 tubes).
2. All above tubesheet indications $\geq$ 30% in the outlet (115 tubes).
3. A random sample across the bundle (40 tubes).
4. Selected tubes in the immediate vicinity of two previously explosive plugged tubes where the plugs were suspected of leaking (7 tubes).

The sample described by items 1, 2, and 3 above was intended to provide the information necessary to calculate the corrosion rates exhibited in the regions of concern. Also, this sample contained a sufficient number of tubes with above tubesheet indications on the inlet side to allow calculations of thinning rates in this region. All tubes in items 1, 2, and 3 were inspected full length (tubesheet to tubesheet).

The initial inspection scope was expanded as a result of inspection findings which ultimately resulted in the inspection scope shown in Tables II.1 through II.6. Inspection scope expansions were developed in general accordance with the intent of Regulatory Guide 1.83, Technical Specifications and discussions between the NRR Staff and Carolina Power & Light Company. The final inspection scope was concurred with in principle via telephone by the NRC.

c. Results

The results of the eddy current inspections indicated the presence of degraded and/or defective tubing in four distinct regions of the S/G tube bundles:

1. <u>U-bend Region</u>

The U-bend section of tubing in some peripheral tubes exhibit wall corrosion typical of phosphate thinning. This occurs primarily on the hot leg side of the S/G's below the #3 antivibration bars down to 2 1/2 inches above the sixth support plate (beginning of the bend transition). The same general groups of peripheral tubes also exhibit thinning (not fretting) at some antivibration bar contact points.

2. <u>Above Tubesheet Region</u>

The central area of the tube bundle on the inlet and outlet sides of the S/G's exhibit tubewall thinning believed to be due to phosphate corrosion in the length of tubing from the top of the tubesheet up to approximately 15 inches above the tubesheet, but primarily 0-6 inches above the tubesheet. This corrosion is generally attributed to the presence of phosphate rich sludge in the S/G and the region affected is consistent with the region where sludge accumulation is anticipated.

3. <u>Crevice Region</u>

The central region of the tube bundle on the inlet side of the S/G's exhibits corrosion indicative of a cracking mechanism in the unrolled length of tubing in the tubesheet. This is assumed to be intergrannular attack concurrent with stress corrosion cracking as has been observed at other Westinghouse plants.

4. <u>Tube Support Region</u>

The section of primarily peripheral tubes which pass through tube support plates exhibit tube wall corrosion at or just above the support plates on the inlet and outlet sides of the S/G's. The statistical spread of the eddy current indications is indicative of a thinning mechanism and is attributed to phosphate thinning.

A list of tubes plugged and an explanation of the reason for plugging is provided for each S/G in Table II.7.

III. Tube Wall Corrosion Rates:

S/G tube wall corrosion rates have been calculated for the U-bend region and top of the tubesheet/above tubesheet region. Corrosion rates were calculated by comparison of eddy current signals from consecutive inspections. Actual eddy current signals were compared to obtain the most accurate measurement of degradation which occurred in the operating period between inspections. Only indications which were 20% through wall or greater in both inspections were utilized to make these calculations. The calculated corrosion rates for the 5.4 EFPM operating period from October, 1980 to May, 1981 are presented below:

S/G	Top of Tubesheet/Above Tubesheet %/EFPM		U-bend
	Hot Leg	Cold Leg	
A	.46	.22	-.036
B	.34	.75	.38
C	.20	.56	--

IV. Evaluation of the Eddy Current Results:

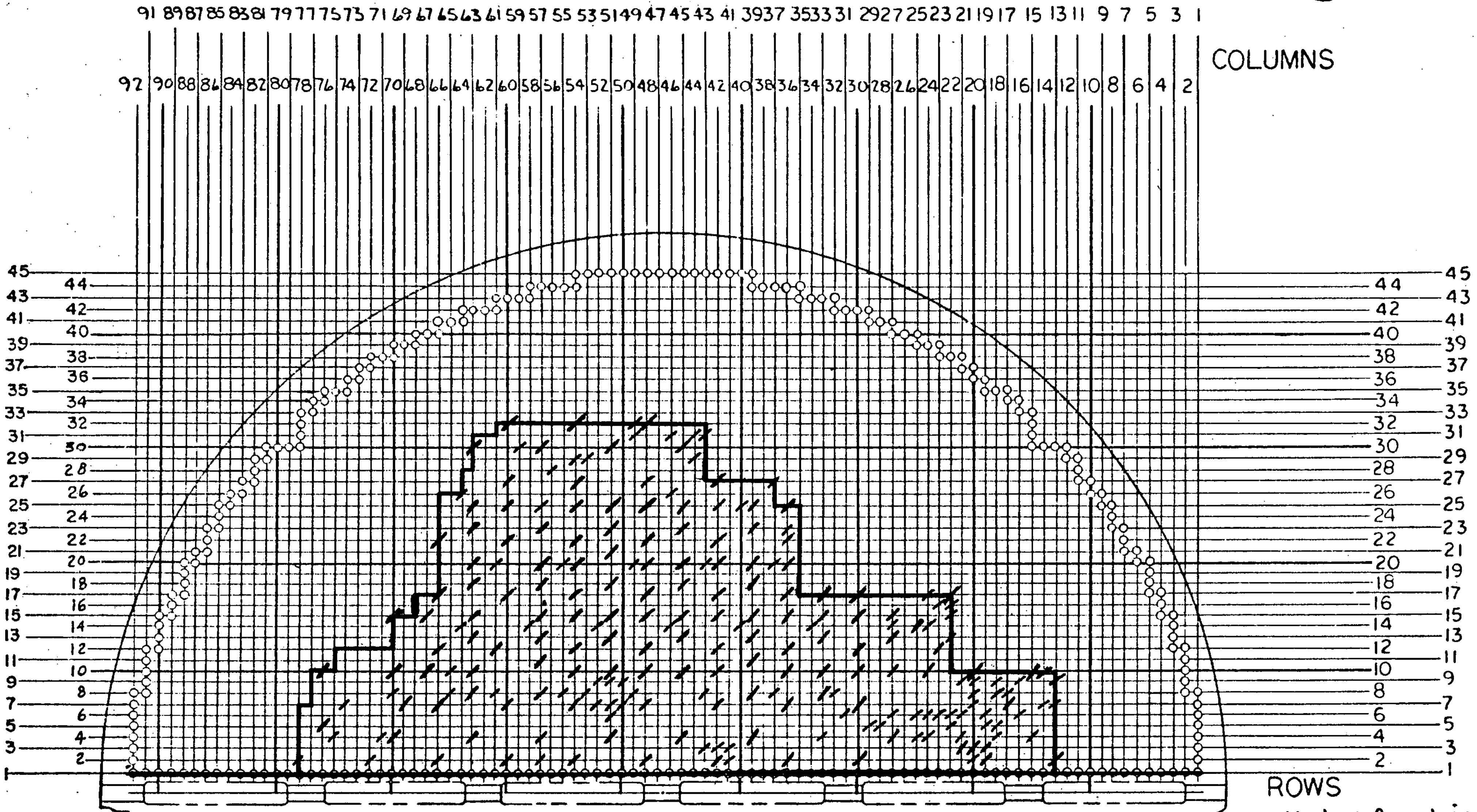
Review of the detailed EC results revealed slow continuation of tubewall degradation in locations where prior penetrations were present; i.e. the corrosion rates, calculated by comparing the observed EC depth estimates with the estimates from the prior (August, 1980) inspection, were generally well under 1% per EFPM, except for the tubesheet crevice region where no estimates were possible. Additional tubes, whose behavior was not characterized by these slow growth rates, exhibited large growth, changing from undetectable to values in excess of the plugging criterion. These

tubes were divided mainly between the U-bend region and the hot leg tubesheet area. Because both hot leg and cold leg tubesheet regions incurred comparable numbers of tubes plugged and since U-bend plugging was known (from the August, 1980 tube pull) to result from tubewall thinning, the cause for all these regions was ascribed to thinning. This conclusion was reinforced by the general character of the EC population statistics which were very similar to those observed in cases of known thinning. The tubesheet crevice tubes plugged exhibited the statistical distribution typical of cracking.

V. Return to Power Operation:

The limiting corrosion rate calculated from the EC data applied to the U-bend regions permitted operation for the remaining core life until the next refueling. Because of the enhanced corrosion rate observed on those tubes which had no prior apparent penetration, it was resolved that Robinson 2 would be operated at or below 2200 MWt. This was done because of the apparent correlation between the events of enhanced U-bend degradation and periods of 2300 MWt power operations - 6 weeks in 1979 prior to the March/April, 1980 inspections, and 9 weeks in 1980-81 prior to the May-June, 1981 inspection. The incidence of tube cracking in the tubesheet crevices does not pose a safety-related question because of the reinforcing effect of the tubesheet which prevents potential tube rupture or limits the tube leakage in case such an event occurs. On these bases, the plant was returned to power with a prospective commitment to perform a 100% EC examination at the refueling outage.

SERIES 44



Inside and including boundary: Inspected through 2nd support

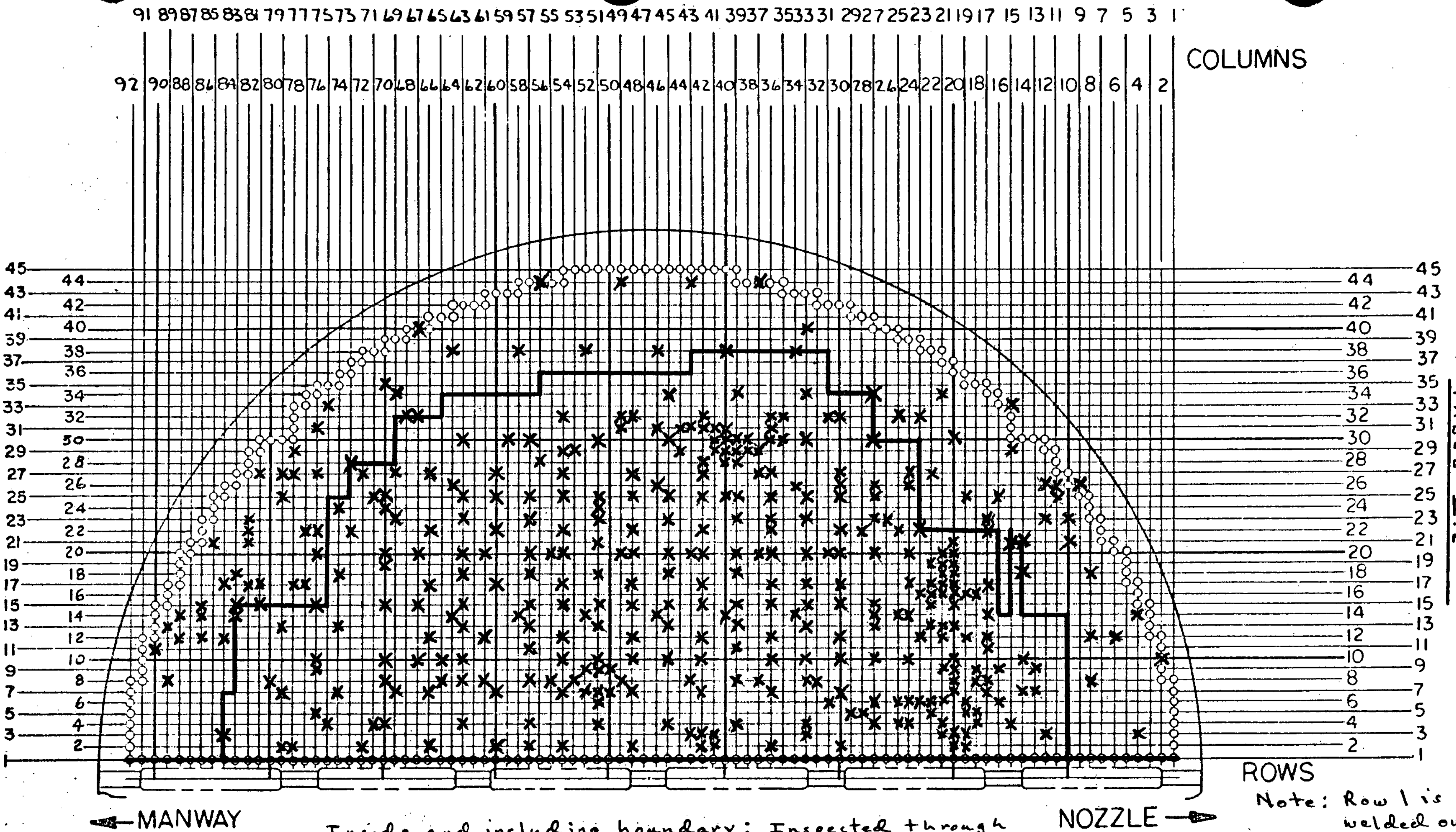
Outside boundary and / : Inspected through u-bend

Note: Row 1 is welded over

TABLE II.1

INSPECTION SCOPE: A S/G INLET

SER 44



Note: Row 1 is welded over

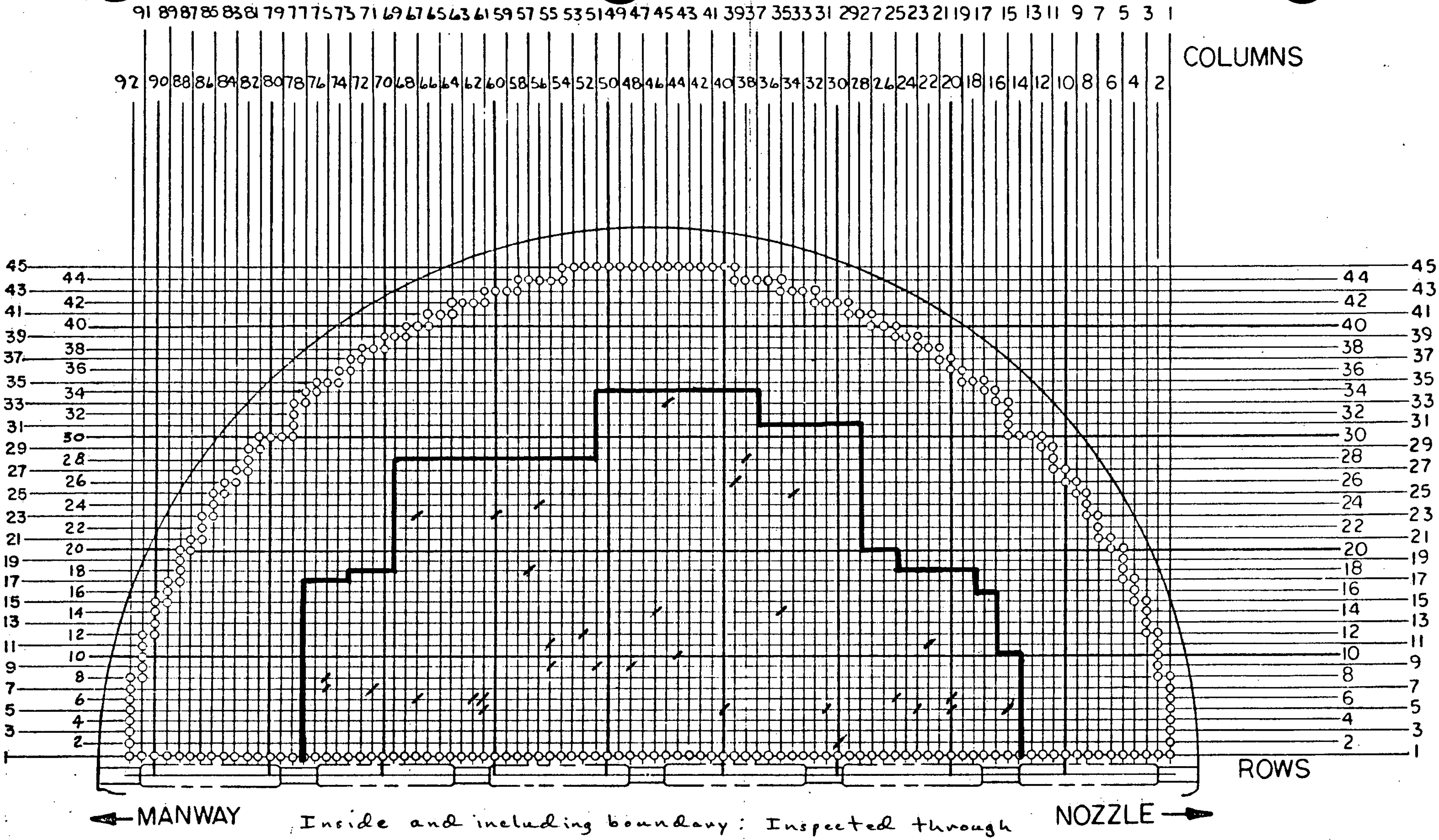
Inside and including boundary: Inspected through 2nd support

x : Inspected through 6th support

INSPECTION SCOPE: A S/G OUTLET

SER S 44

TABLE II.3



Inside and including boundary: Inspected through 2nd support

Outside boundary and /: Inspected through u-bend

INSPECTION SCOPE: B S/G INLET

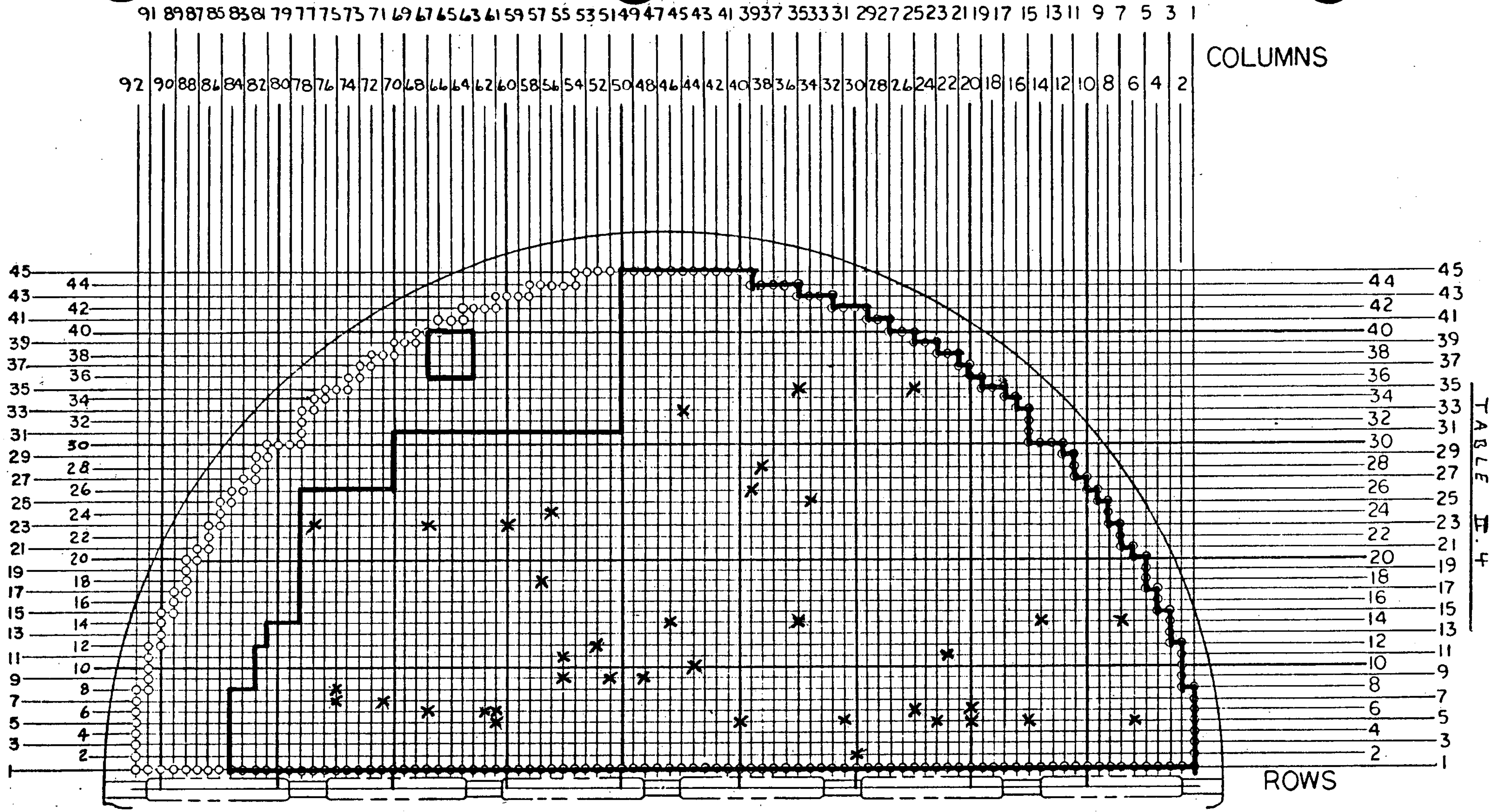


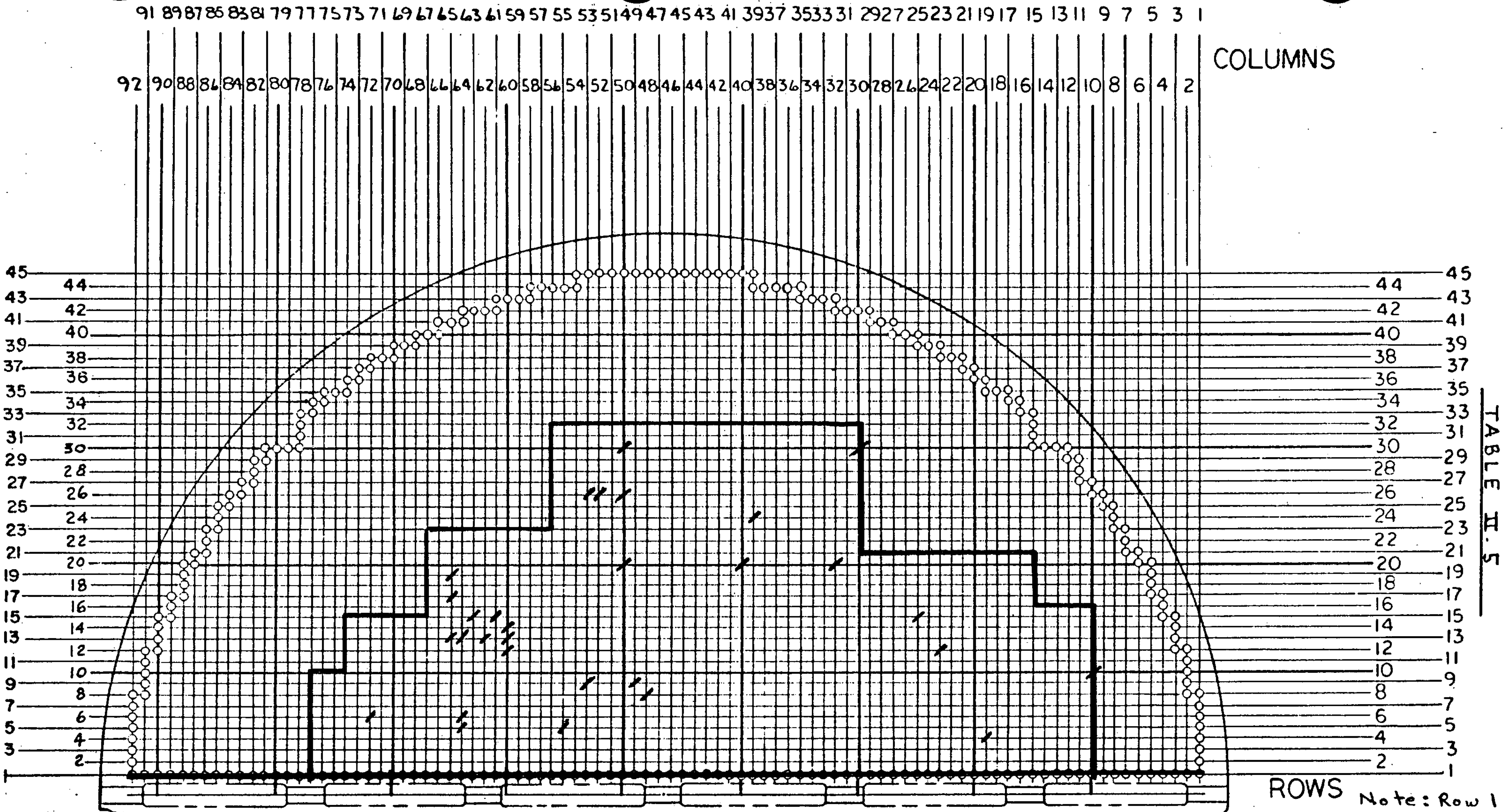
TABLE II.4

MANWAY Inside and including boundaries: Inspected through 2nd support NOZZLE

x : Inspected through 6th support

INSPECTION SCOPE: B S/G OUTLET

SE[illegible] 44



← MANWAY

NOZZLE →

Inside and including boundary: Inspected through 2nd support

Outside boundary and /: Inspected through u-bend

INSPECTION SCOPE: C S/G INLET

SERIES 44

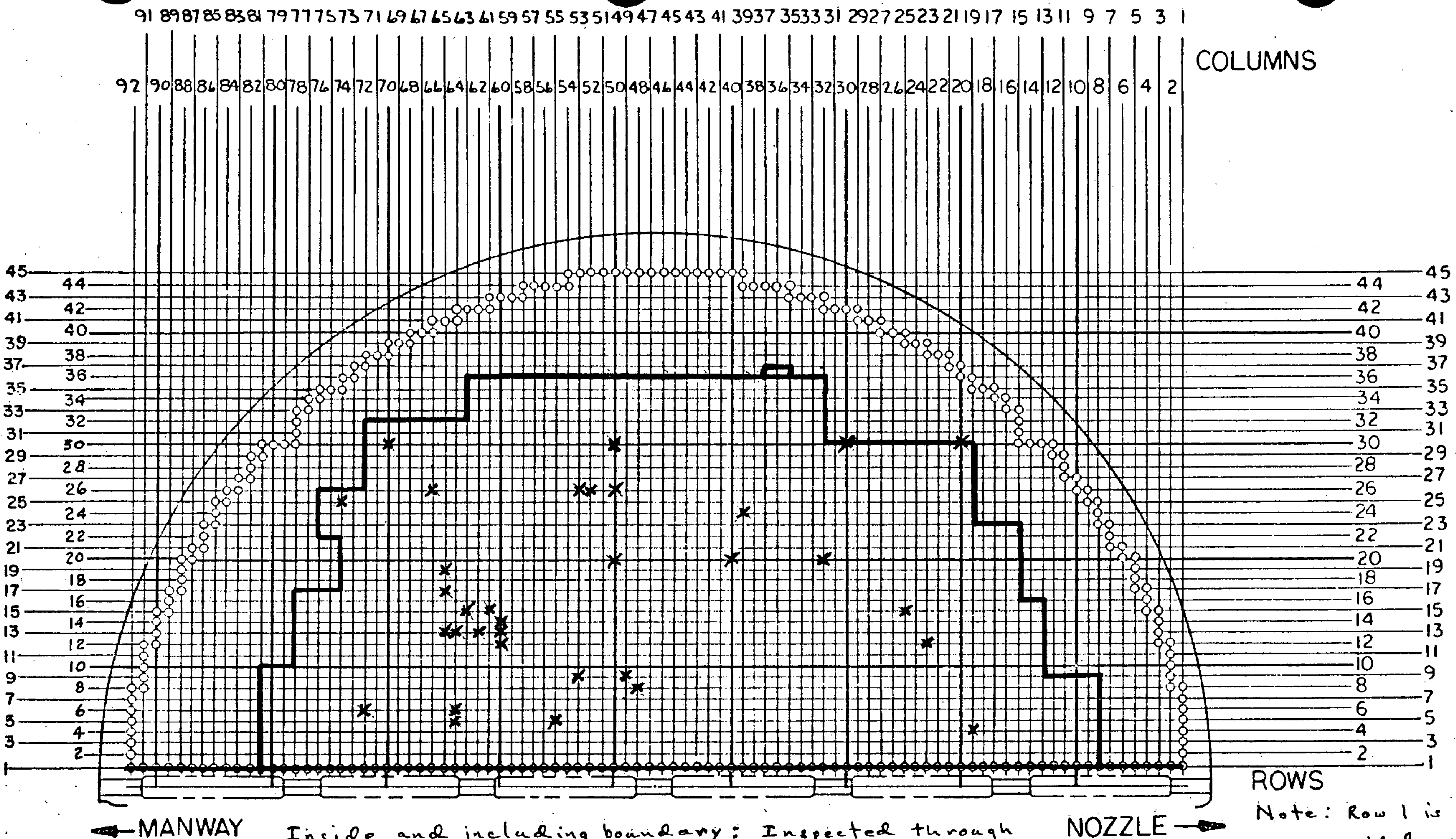


TABLE II.6

Note: Row 1 is welded over

Inside and including boundary: Inspected through 2nd support

x : Inspected through 6th support

INSPECTION SCOPE: C S/G OUTLET

TABLE II.7

LIST OF TUBES PLUGGED

"A" STEAM GENERATOR

	Row	Column	% Indication	Location
Hot Leg Above Tubesheet/Top of Tubesheet:	9	51	66	3" ATS
	7	52	54	2" ATS
	11	17	73	15" ATS
	6	24	49	1" ATS
	14	27	81	11" ATS
	12	32	59	1" ATS
	5	34	75	10" ATS
	3	34	67	2-3" ATS
	4	42	55	4" ATS
	14	56	56	1" ATS
	23	60	86	2" ATS
	9	63	50	TTS - 2½" ATS
Hot Leg Tubesheet Crevice:	7	11	62	5" ATE
	10	33	86	8" ATE
	15	39	90	20" ATE
Hot Leg Tube Support Plate:	12	3	52	2" A#2TSP
	42	36	60	5" A#3TSP
	43	32	50	2" A6TSP
Hot Leg U-Bend:	24	74	63	5" A6TSP
	22	76	56	5" A6TSP
	22	77	51	13" A6TSP
	15	81	52/59	18" A6TSP/9" A6TSP
	22	82	95	#3-#4 AVB
	12	84	52	4" A6TSP
	17	84	49	4" A6TSP
	29	25	52	6" A6TSP
	40	64	80	#3 AVB
Cold Leg Above Tubesheet/Top of Tubesheet:	8	18	49	6" ATS
	13	20	49	3-6" ATS
	2	20	(86m) 52	(TTS) 1" ATS
	31	36	50	1-8" ATS
	31	40	53	2½-5" ATS
	3	41	50	3" ATS
	31	41	49	2½-5" ATS
	31	44	49	1-7" ATS
	3	33	60	2½" ATS

"B" STEAM GENERATOR

	Row	Column	% Indication	Location
Hot Leg Above Tubesheet/Top of Tubesheet:	15	21	66	6" ATS
	27	31	52	10" ATS
	27	32	81	12" ATS
	28	32	79	12" ATS
	26	35	75	TTS
	27	36	78	TTS
	32	38	83	4" ATS
	17	45	53	½" ATS
	36	46	74	2" ATS
	16	50	55	10" ATS
	27	50	55	TTS
	36	52	89	5" ATS
	18	55	56	1" ATS
	26	55	52	1" ATS
	20	59	58	18" ATS
	41	66	64	7" ATS
	4	68	80	4" ATS
	26	68	79	4" ATS
	2	72	60	½" ATS
Hot Leg Tubesheet Crevice:	19	25	75	0-10" ATE
	29	28	90	0-17" ATE
	17	33	89	5" ATE
	26	33	86	7" ATE
	13	34	84	4" ATE
	14	35	95	7" ATE
	14	36	79	10" ATE
	28	38	78	7" ATE
	13	40	87	5" ATE
	14	40	87	10" ATE
	19	40	91	6" ATE
	23	40	63	12" ATE
	31	40	87	15" ATE
	34	41	77	8" ATE
	13	42	79	18" ATE
	23	42	90/82	3" ATE/11" ATE
	19	43	56	10" ATE
	31	43	80	6" ATE
	23	44	82	7" ATE
	26	44	84	6"-8" ATE
	31	44	87	3" ATE
	31	45	89	10" ATE
	19	46	80	15" ATE
	24	46	91	7" ATE
	22	47	95	10" ATE
	23	47	89	10" ATE
	25	47	83	10" ATE
	24	50	76	8" ATE

"B" STEAM GENERATOR CONTINUED

	Row	Column	% Indication	Location
	9	51	69	5" ATE
	9	53	94	10" ATE
	17	53	89	10" ATE
	30	53	92	3" ATE
	17	55	90	8" ATE
	24	55	94	5" ATE
	24	56	83	2½"-5" ATE
	35	57	80	10" ATE
	37	57	85	5" ATE
	13	59	87	10" ATE
	31	47	Distorted	10" ATE
	31	53	Distorted	10" ATE
	18	67	Distorted	2½"-10" ATE
Hot Leg Tube Support Plate:	12	2	66	1" A5TSP
	14	3	85	1" A5TSP
	44	57	83	#2 TSP
	33	78	79	3" A5TSP
Hot Leg U-Bends:	14	5	77	4" A6TSP
	17	5	50	10" A6TSP
	25	19	67	5" A6TSP
	33	19	57	15" A6TSP
	23	25	58	4" A6TSP
	38	26	49	6" A6TSP
	32	77	68	4" A6TSP
	26	78	60	5" A6TSP
	12	83	89	#2 AVB
	16	83	49	6" A6TSP
	12	86	51	6" A6TSP
	12	89	50	6" A6TSP
	10	85	60	5" A6TSP
	26	22	60	5" A6TSP
Cold Leg Above Tubesheet/Top of Tubesheet:	19	21	54	1" ATS
	22	23	49	TTS
	6	24	52	5" ATS
	6	27	51	7½"-12" ATS
	25	33	53	5" ATS
	21	45	53	10" ATS
	6	53	53	8" ATS
	6	55	49	TTS-10" ATS
	6	56	56	TTS-10" ATS

"B" STEAM GENERATOR CONTINUED

	Row	Column	% Indication	Location
	6	57	52	TTS-10" ATS
	10	57	49	14" ATS
	6	58	49	5"-10" ATS
	2	59	49	½" ATS
	6	59	52	5"-10" ATS
	6	61	55	7" ATS
	6	62	60	2½"-11" ATS
	6	64	54	6" ATS
	2	65	49	½" ATS
	8	65	54	½" ATS
	9	65	53	2" ATS
	8	68	49	6"-11" ATS
	2	69	52	2" ATS
	17	69	51	6" ATS
	2	70	57	1" ATS
	5	71	49	1" ATS
	19	71	55	TTS-5" ATS
	3	72	51	1" ATS
	9	72	50	7"-9" ATS
	15	72	48	6" ATS
	9	74	49	2"-3" ATS
	8	75	50	½"-5" ATS
	9	78	54	3"-5" ATS
	14	68	52	7½" ATS
Other:	11	90	47	15" A6TSP

NOTE: Plugged prior to final calculation of corrosion rate.

"C" STEAM GENERATOR

	Row	Column	% Indication	Location
Hot Leg Above Tubesheet/Top of Tubesheet:	30	38	60	5" ATS
	17	42	48	TTS
	15	24	49	14" ATS
	17	39	89	TTS
	17	40	59	TTS
	5	53	87	3" ATS
	6	74	86	10" ATS
	11	77	50	6" ATS
	14	67	62	15" ATS
	35	52	48	8"-8½" ATS
	35	53	59	5" ATS
	2	47	69	ATS
Hot Leg Tubesheet Crevice:	32	39	89	10" ATE
	24	33	73	7½"-13" ATE
	6	34	50	7½"-15" ATE
	15	38	95	15" ATE
	16	39	82	20" ATE
Hot Leg Tube Support Plate:	44	35	52	1" A#2TSP
Hot Leg U-Bend:	43	54	56	#2 AVB
	16	86	70	5" A6TSP
	27	18	57	5" A6TSP
	12	88	69	2" A6TSP
Cold Leg Above Tubesheet/Top of Tubesheet:	14	19	48	2" ATS
	4	22	82	5" ATS
	14	26	59	5"-12" ATS
	14	27	55	5"-12" ATS
	14	28	52	5"-12" ATS
	5	32	52	2½"-12" ATS
	8	48	49	10" ATS
	9	54	48	13" ATS
	6	56	50	12" ATS
	2	64	50	TTS
	21	69	48	3"-4" ATS
Other:	13	27		

NOTE: Plugged due to obstruction on cold leg side approximately 6 inches above tube end.