Westinghouse Energy Systems

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WCAP-12294
REVISION 2

INDIAN POINT UNIT 2
STEAM GENERATOR GIRTH WELD/
FEEDWATER NOZZLES REPORT
SPRING, 1989 OUTAGE
CONSOLIDATED EDISON OF NEW YORK

OCTOBER 1989

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WESTINGHOUSE ELECTRIC CORPORATION
ENERGY SYSTEMS BUSINESS UNIT
P.O. BOX 355
PITTSBURGH, PA 15230-0355

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Following is a revision to WCAP-12294 Revision 2. Changes to the text are identified by a vertical double bar along the margin of the changed page.

1.0 INTRODUCTION

This report presents the recent inspections performed on the Indian Point Unit 2 steam generators, the inspection results and the follow-up actions taken to minimize the potential of recurrence of linear indications in the girth welds and feedwater nozzles.

Initially, examinations were conducted during this outage on the steam generator (SG) girth weld (transition cone upper girth weld) and feedwater nozzle area in SG 22. Linear indications were detected and as a result examinations were increased to include all four SG's.

All indications were ground out and weld repairs with post weld heat treatment were accomplished on SG 22.

The probable mechanism of the occurrence of the cracks has been established as corrosion fatigue caused by a combined action of thermal cycling, oxygen in the auxiliary feedwater and copper from the feedwater system.

To minimize the cause for the fatigue corrosion mechanism, the downcomer resistance plates were removed. Additionally, the controls of the feedwater low flow valves have been modified and consideration is being given to a nitrogen gas cover in the condensate storage tank or deaeration.

1.1 Summary of Inspection Results

During the current refueling outage, visual (VT) and magnetic particle (MT) examinations were conducted initially on 1/3 of the inside circumference of the SG 22 girth weld. These examinations were conducted as part of the ongoing steam generator girth weld examination program as identified previously in a Con Edison letter to the NRC dated December 11, 1987. Linear indications were detected during this examination. Subsequently 100% of the inside circumferences of the girth welds in all four steam generators were inspected. Linear indications were also detected in these additional examinations. Details regarding the as-found indications, the grindout geometry and planned weld repairs and post weld heat treatment are discussed in subsequent sections of this report.

During this outage, a VT examination was also conducted on the SG 22 feedwater nozzle inside radius section in accordance with Inservice Inspection Program relief request 25, previously approved by the NRC in a letter dated December 24, 1987. The visual examinations detected several linear indications within the nozzle inner radius section in the bottom 120° segment of the nozzle. Visual and liquid penetrant tests were subsequently performed on the nozzles of all four steam generators. SG 22 and 23 nozzles contained similar indications whereas none were detected in SG 21 and 24. During the course of performing liquid penetrant tests on the nozzles, linear indications were also detected in support bracket welds directly below the nozzle inside radius section on SG 22 and 23. No such indications were detected in SG 21 and 24.

As a result of detecting the linear indications in the nozzle inner radius section an expanded inspection program was initiated to determine the overall condition of the feedwater nozzles. This program included radiography of all four nozzle to feedwater inlet piping welds, ultrasonic examinations of all four nozzle bores, and a borescopic examinations of segments of the SG 22 and 23 thermal sleeve inside diameter surface and outside diameter surface and the nozzle bore inside diameter surface. The indications on the SG 22 and 23 nozzle inner radius have been removed by grinding and the indications on the SG 22 and 23 support bracket welds have been removed and repair welded.

Details of the as-found indications on the nozzle inner radius sections and the support brackets, the expanded inspection program, the grindout geometry and support plate repairs are discussed in subsequent sections of this report.

1.2 Overall Action Plan

As a result of the inspection and analysis performed, an overall action plan has been implemented to address the postulated mechanisms and minimize the potential of recurrence of the indications. The plan includes the following steps:

1. Removal of all indications (cracks)

2. Repair welding
   a) Girth weld in SG 22 to an equivalent maximum grindout depth of 3/4 in.

   b) Support bracket attachment areas in SG 22 and 23

3. Removal of downcomer flow resistance plates (DFRP)

4. Modification of main feedwater flow bypass regulator valves

5. Operational controls

6. In-service inspection/mid-cycle outage

1.2.1 Removal of All Indications

All indications were removed by grinding and the surface was examined by MT techniques to assure that no linear indications remain. The primary method used dry powder with an AC yoke. In addition, several ground out areas were cooled locally and MT tested with dry powder and DC magnetization. No indications were detected.

1.2.2 Repair Welding

Analysis showed that a girth weld grindout of approximately 1 inch depth is suitable for continued operation. Steam generators 21, 23 and 24 meet the above criterion without additional repair. Steam generator 22 had a larger number of indications and a higher crack growth rate during the previous cycle. Thus to provide a greater margin for SG 22, all grindout areas were rewelded to leave a maximum grindout of less than 3/4 in. A subsequent post weld heat treatment (PWHT) at 1125 ± 25°F will be performed. Table 1.2-1 shows the grindout areas to be welded. An RT examination will be made of the repair areas. After PWHT, MT examination will be made of 100% of the girth weld inner circumference.

The support bracket welds with indications were restored to original design configuration. In SG 22 a shielded metal arc welding (SMAW) process with E-7018 filler metal was used. The PWHT for the girth weld repair was used for heat treating these repairs. Both vertical welds on both support brackets showed indications with the deepest area to 0.36 in.

The grindout repairs to the support bracket in SG 23 were in the attachment welds. A half bead technique with E9018M filler was used. The vertical welds on both support brackets showed indications to a maximum depth of 0.36 in.

1.2.3 Downcomer Flow Resistance Plate

The plates were removed to prevent the damming action which might concentrate the colder water in the area of the girth weld during the injection of auxiliary feedwater.

1.2.4 Main Feedwater Bypass Flow Regulator Valve Modification

This modification installs a timer that can delay closure of the main feedwater flow bypass flow regulator valves following a reactor trip coincident with low Tave ($\leq$ 541°F) signal. This modification in conjunction with operation of the bypass flow regulator valves in the open position, provides hot main feedwater flow to the steam generators following a trip. This will enhance maintaining the steam generator girth welds and the feedwater nozzle in relatively warm water when the auxiliary feedwater enters the steam generator nozzle and feedwater ring of the steam generator, which could minimize potential thermal shock to the girth welds and feedwater nozzle.

The main feedwater regulator valves will still close on the reactor trip/low Tave signal. Both the main and bypass regulator valves will still be closed by the independent circuitries of Safety Injection and High Steam Generator Water Level. The timer will be set to zero until the optimum setting is determined. Implementation of the modification is under evaluation.

1.2.5 Operational Control

1.2.5.1 Feedwater Chemistry

All plant INPO chemistry parameters, as identified in the Chemistry Performance Index are on the average 2/3 less than the corresponding industry guideline values and show a downward trend. Figure 1.2-1 shows this.

At the same time, chemistry appears to play an adverse role in two abnormal plant operating modes. For reactor trips and plant operation in the hot standby mode, relatively cold, oxygenated auxiliary feedwater is pumped into the steam generators. The results of the metallurgical evaluation indicate that the oxygen contained in this water, acting catalytically in the presence of copper, causes pitting in the steam generator girth weld area. Pits in the range of 20 to 25 mils diameter correlate strongly as nucleation sites for the cracks observed.

Continuing improvements have been made to both the water treatment facility and to condensate and feedwater components to ensure the water quality could meet the requirements of the SG chemistry limits. These include the change out of the material in external feedwater heaters to remove copper sources and the addition of prefilters to further reduce the chloride content in makeup water. Oxygen concentrations have also been reduced over the past several years through a rigorous program of monitoring for and eliminating of air in-leakage. As a result, O_2 in feedwater is being maintained generally at less than 5 ppb. However, during periods of operation when the auxiliary boiler feedwater pumps supply water to the SGs, no current method exists for assuring the O_2 in the feedwater is maintained below 50 ppb. A potential correction to this problem would be the installation of a nitrogen cover gas blanket on the condensate storage tank or deaeration to mitigate this effect. This modification is currently being evaluated.

As part of an overall improvement program, consideration is being given to retubing the Indian Point 2 condensers with Titanium.

1.2.5.2 Leakage Detection

Multiple detection methods are located within containment for monitoring system leakage. The methods are primarily directed to detection of leakage from the Reactor Coolant System and their operability and out-of-service times are controlled by the requirements of the Technical Specification. (Section 3.1.F. "Reactor Coolant System Leakage and Leakage into the Containment Free Volume"). The reactor cannot be brought above cold shutdown unless the following leakage detection and removal systems are operable:

(1) Two containment sump pumps
(2) Two containment sump level monitors
(3) A containment sump discharge line flow monitoring system
(4) Two recirculation sump level monitors
(5) Two reactor cavity level monitors
(6) Two of the following three systems
  (a) A containment atmosphere gaseous radioactivity monitoring system
  (b) A containment atmosphere particulate radioactivity monitoring system
  (c) The containment fan cooler condensate flow monitoring system.

The above leakage detection methods represent a comprehensive monitoring system which is capable of detecting leakage from different systems. Those detection methods, dependent upon sensing airborne radioactivity levels, are limited in their application to Reactor Coolant System Leakage. However, those which monitor water accumulation or flow would detect process equipment pressure boundary leakage including significant secondary side steam generator leakage. Of the various methods, the radioactivity monitors are the most sensitive and detect the lowest amount of leakage. Except for beginning of life, the absence of radioactivity indication would indicate that leakage is from a source other than the Reactor Coolant System. Thus all of the monitoring systems are of value in detection of a breach in the pressure boundary of a steam generator.

The Technical Specifications establish limits for total leakage into the containment from all sources. If the limits cannot be met, the source of leakage must be reduced to allowable limits or the plant be brought to cold shutdown within the prescribed time periods. Relative to the steam generators, the pertinent limit is 10 GPM (total).

Of the various monitoring schemes, the containment fan cooler condensate flow monitoring system measures the moisture condensed from the containment atmosphere by the cooling coils of the main air recirculation units. Steam generator leakage could result in an increase in containment humidity. Condensate flows from approximately 1 gpm to 15 gpm per detector can be measured. Condensate flows less than 1 gpm may be determined by periodic observation of water accumulation in the standpipes of the condensate collection system. Measuring flows greater than 15 gpm with this system is also possible. By procedure, containment fan cooler unit condensate flow monitoring is performed once every four hours. An additional method of monitoring water buildup in the containment atmosphere is possible via changes in the dew point of the containment atmosphere. The change in water content of the containment atmosphere is also possible via this route.

Monitoring of the containment sump level monitor actuation, containment sump pump flow, recirculation sump level monitor actuation or recirculation sump level monitor actuation provide a more direct means of quantifying leakage into the containment. The containment and recirculation sump inventories are monitored once a shift; their related pumps are demonstrated to be operable on a monthly basis.

Operation procedures currently require containment entry at 5 gpm (refer to 2.7.1) to identify the source of leakage should a leakage detection system annunciate. Additionally, routine containment entry is required once a month for inspection purposes.

Any alarm annunciation would be followed by a timely containment inspection of the source of leakage.

1.2.6 Inservice Inspections/Mid-Cycle Outage

The following inservice inspections are planned to be conducted for the SG girth welds and feedwater nozzles following the current plant outage.

During a special plant shutdown which will occur approximately at mid-cycle, VT and MT inspections of 1/3 of the inner circumference of the S.G. 22 and 23 girth welds will be conducted. This will include areas of representative repairs, previously ground out areas, and non ground areas. If relevant linear indications are detected, the examination will be extended to 100% of the SG 22 and 23 girth welds and 1/3 of SG 21 and 24. If relevant linear indications are found in SG 21 and 24 the examinations will extend to 100% of these welds.

Simultaneously inspection of the feedwater nozzle areas is planned. A VT and MT (or PT) will be conducted on the nozzle inner radius section in the lower 180° segment and on the welds of the support brackets on SG 22 and 23. If indications are found, the examinations will be expanded to the SG 21 and 24 nozzles and/or brackets, as applicable.

If an unplanned outage of sufficient duration occurs within a few months prior to the planned mid-cycle outage, the above examinations may be performed at that time in lieu of conducting the inspections later at the planned mid-cycle outage.

The above examinations VT and MT (or PT) on girth weld and feedwater nozzle areas will also be repeated during the next refueling outage.

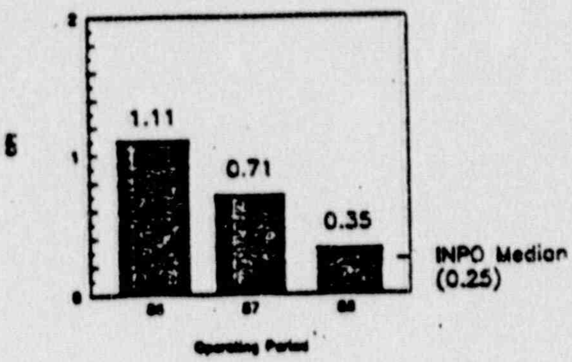
Subsequent to grinding out/repair welding the girth welds during this outage, ultrasonic baseline mapping and future inservice volumetric testing of the girth welds will not be accomplished as specified in ASME Section XI. Ultrasonic examinations during 1987 following girth weld grindout indicate that the complex grindout geometries preclude meaningful ultrasonic examinations. In lieu of volumetric examinations, visual and MT examinations of the interior circumference of the girth weld will be substituted for future Section XI exams.

Indian Point #2

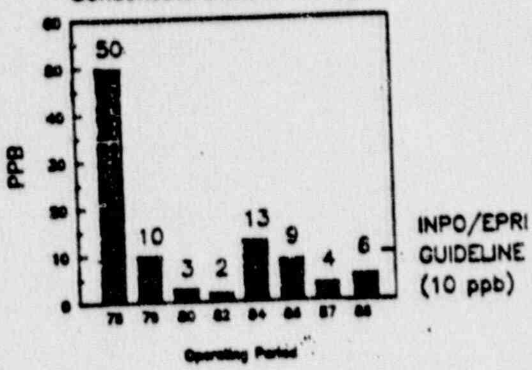
Chemistry Performance Index (CPI)

- Consists of five secondary-side water quality parameters
  - Condensate System – Dissolved Oxygen (10 ppb)
  - Steam Generator Blowdown
    - Chloride (20 ppb)
    - Sulfate (20 ppb)
    - Sodium (20 ppb)
    - Cation Conductivity (0.8 uS/cm)
- Used as a report card to track station performance over time and relative to the industry
- Implemented by INPO effective January 1988

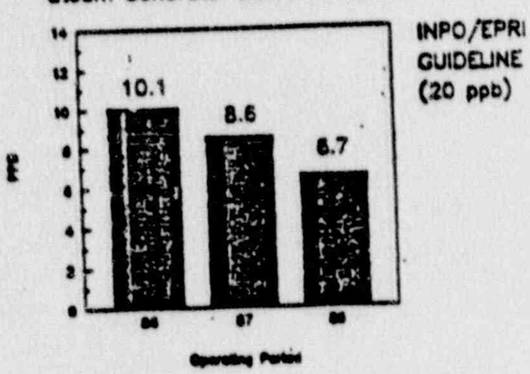
INPO Chemistry Performance Index (CPI)



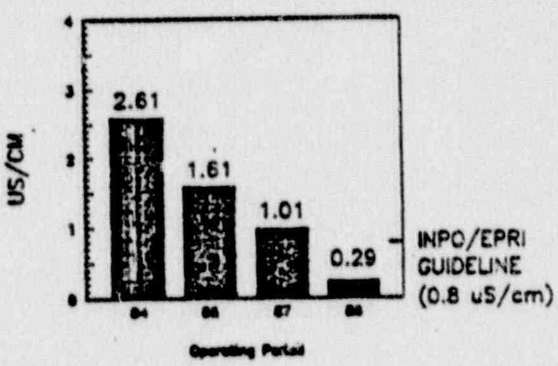
Condensate Dissolved Oxygen



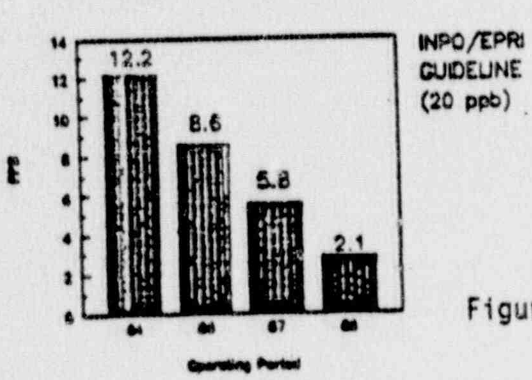
Steam Generator Blowdown Sulfate



Steam Generator Blowdown Cation Conductivity



Steam Generator Blowdown Sodium



Steam Generator Blowdown Chloride

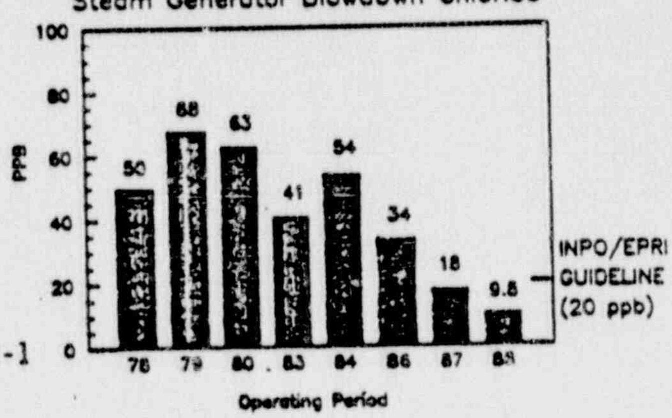


Figure 1.2-1

TABLE 1.2-1

AREAS IN SG 22 DEEPER THAN 3/4 IN. TO BE REPAIR WELDED

Zone No.	Length (in.)	Width (in.)	Start from Zone Line (in.)	Vertical Distance from Reference Line In.
6	5	1 1/2	17	7 1/2
	4	1 1/2	24*	8
	5	2	38*	7 1/4
7	5	3	9	8
	6	3	26*	7 1/4
8	8 3/4	4	3 1/2*	8
	6	3	20*	7
9	11	3	1	7 3/4
	5	3	6	8
11	10	5	9	7

*Approximate

2.0 STEAM GENERATOR GIRTH WELD DETAILS

2.1 Industry Experience

Following the Indian Point 3 girth weld shell leak, several utilities performed NDE inspections in the girth weld region of their steam generators. A total of five plants reported linear indications on the inner circumference of the girth welds. The plants are Indian Point Units 2 and [ ]^{g}, plant A, [ ]^{g}, plant C and [ ]^{g}, plant D 2, and [ ]^{g}, plant B. In all five plants, the indications were removed by grinding. Previously, only one of the five [ ]^{g}, plant A required weld repair. Subsequent reinspections at three plants have revealed no indications at two: [ ]^{g} plant D and [ ]^{g}, plant A and one shallow indication [ ]^{g}, plant C which was removed by light grinding (less than 0.020 inches in depth). The inspection techniques used, the number of steam generators inspected, and other pertinent data are summarized in Tables 2.1-1, 2.1-2, 2.1-3 and 2.1-4. A general outline of the girth weld region is shown in Figures 2.1-1 and 2.1-2.

Few plants with downcomer flow resistance plates installed have performed MT examinations similar to Indian Point 2. Only [ ]^{g}, plant C and [ ]^{g}, plant D had downcomer flow resistance plates in place prior to the first MT inspections. (The plates were removed in order to perform the inspections and were not reinstalled.).

Additionally, the only remaining plants with Westinghouse Series 51 steam generators which presently have their downcomer flow resistance plates in place are [ ]^{g}, plant E, [ ]^{g}, plant F, [ ]^{g}, plant G and [ ]^{g}, plant H. There are no domestic Westinghouse Series 44 steam generators which presently have downcomer flow resistance plates installed.

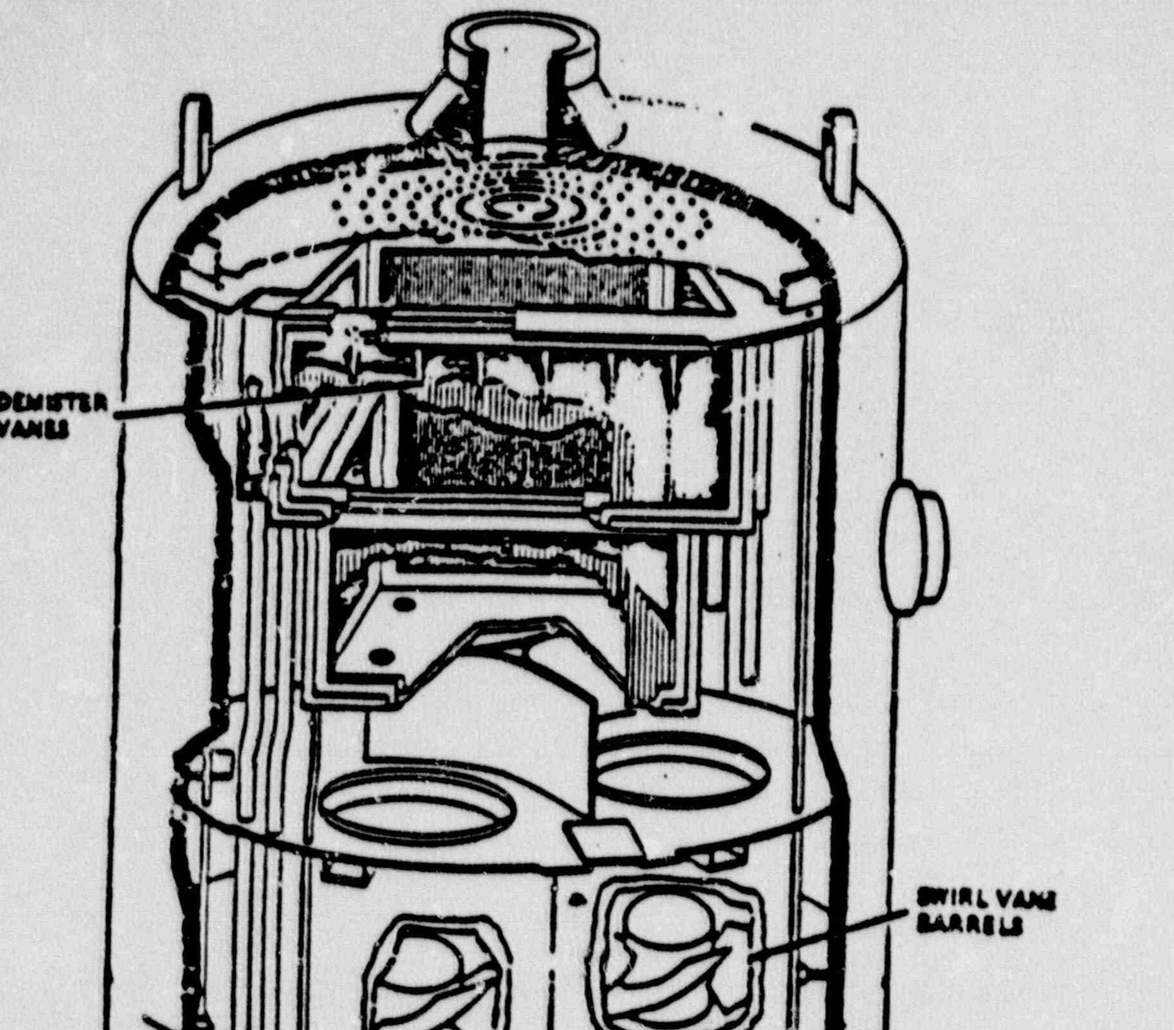
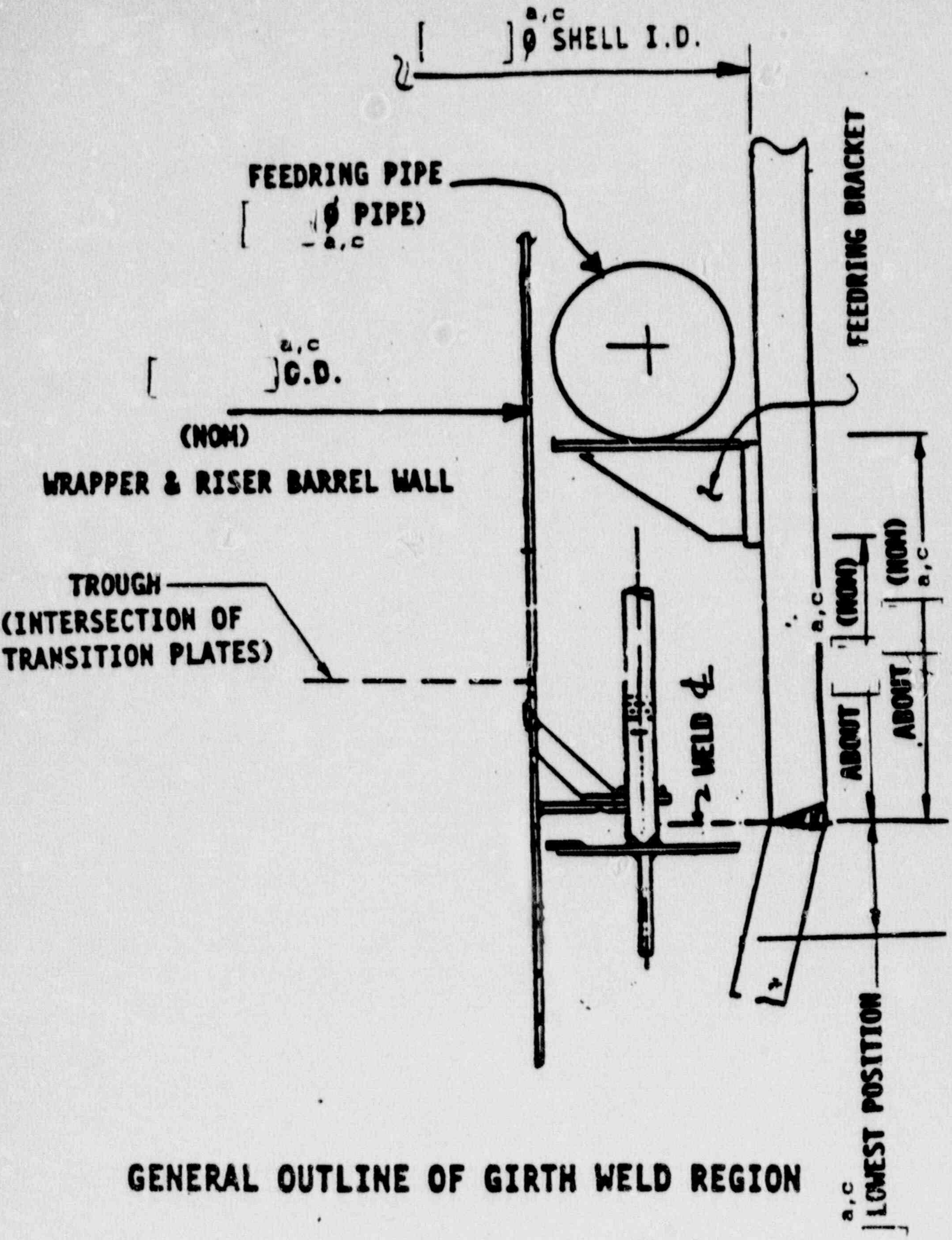


Figure 2.1-1 GENERAL OUTLINE OF WESTINGHOUSE MODEL 44 STEAM GENERATOR



GENERAL OUTLINE OF GIRTH WELD REGION

Figure 2.1-2

INITIAL STEAM GENERATOR GIRTH WELD INSPECTIONS
PLANTS WITH NO REPORTED INDICATIONS

PLANT	S. G. MODEL NO.	YEARS SERVICE	INSPECTION DATA WHEN	INSPECTION DATA RESULTS
g	13	24	10/82	100% UT 1 SG SUBSURFACE INDICATIONS
	33	15	9/83	UT AND VISUAL 2 SG PITS BOTH SG'S W/PITS LINKING TO LINEARS IN SGB
	44	9	3/82	UT AND VISUAL ALL SG PITS AND LINEAR
	44	12	10/82	100% SG023 AND 36° OTHERS LINEAR INDICATIONS SG023 & 23 VISUAL EXAM. JUDGED TO BE WELD UNDERCUT
	51	6	9/82	100% UT 1 SG. 2 RECORDABLE - TYPE UNKNOWN
	51	9	8/82	PARTIAL UT EACH SG. INDICATIONS NEAR ID SURFACE JUDGED TO BE SURFACE GEOMETRY
	51	13	4/83	100% UT 1 SG. INDICATIONS NEAR ID SURFACE JUDGED TO BE SURFACE GEOMETR
	51	12	1985	100% UT ALL SG. PITS AND LINEAR INDICATIONS.

Table 2.1-1

Table 2.1-2

INITIAL STEAM GENERATOR GIRTH WELD INSPECTIONS
PLANTS WITH NO REPORTED INDICATIONS

PLANT	S. G. MODEL NO.	YEARS SERVICE	INSPECTION DATA: WHEN	INSPECTION DATA: RESULTS
	27	10	2/84	100% UT 1 SG
	44	15	9/82	MT 1 SG - Pits
	44	13	11/82	100% ALL SG'S
	51	4	10/82	INSPECTED 1 SG. METHOD UNKNOWN
	51	9	2/84	100% UT 1 SG
	51	5	2/84	100% UT 1 SG
	51	12	11/82	100% UT ALL SG'S
	51	12	11/82	UT 24" TO 40" ALL SG
	51	12	11/82	UT 24" TO 40" ALL SG

* DOWNCOMER OUT IN 1975

GIRTH WELD REPAIR HISTORY

1982 [ ][g] (MODEL 44) REPORTED SHELL LEAK IN S/G #32. UT/MT EXAMINATION CONFIRMED ADDITIONAL INDICATIONS. REPAIRED BY GRINDING/WELDING.

1983 [ ][g] (MODEL 33) UT/MT INSPECTION SHOWED PITTING/LINEAR INDICATIONS. ALL LINEAR INDICATIONS REMOVED BY GRINDING.

1985 [ ][g] (MODEL 51F) UT/MT INSPECTION SHOWED PITTING/LINEAR INDICATIONS. ALL LINEAR INDICATIONS REMOVED BY GRINDING.

1986 [ ][g] (MODEL 51F) UT/MT INSPECTION SHOWED PITTING/LINEAR INDICATIONS. ALL LINEAR INDICATIONS REMOVED BY GRINDING.

Table 2.1-3

GIRTH WELD NO. 6 INDUSTRY INSPECTION SUMMARY

- FOLLOWING [ ][g] GIRTH WELD INDICATIONS, A NUMBER OF UTILITIES PERFORMED INSPECTIONS OF GIRTH WELD NO. 6.
  - FIVE MODEL 51 S/Gs WERE 100% INSPECTED BY UT.
    - NO UNACCEPTABLE INDICATIONS FOUND. ONE S/G EXHIBITED INDICATIONS JUDGED TO BE GEOMETRY.
  - SIX MODEL 51 S/Gs WERE PARTIALLY EXAMINED (APPROXIMATELY 8 FT.) BY UT.
    - NO UNACCEPTABLE INDICATIONS FOUND, ISOLATED INDICATIONS FOUND WHICH WERE JUDGED TO BE GEOMETRY.
  - FOUR MODEL 44 S/Gs WERE 100% UT AND SIX WERE 100% MT.
    - NO UNACCEPTABLE INDICATIONS FOUND.

Table 2.1-4

GIRTH WELD NO. 6 INDUSTRY INSPECTION SUMMARY
(CONTINUED)

- FOLLOWING THE REPAIR OF INDICATIONS AT [IP 3][g] AND [ ][g] SUBSEQUENT UT/MT INSPECTIONS HAVE BEEN PERFORMED:

  - [ ][g] - FOUND (BY MT) ONE SHALLOW INDICATION WHICH WAS REMOVED BY LIGHT GRINDING (<0.02"); INSPECTION WAS EXPANDED BUT NO FURTHER INDICATIONS FOUND.

  - [ ][g] - TWO RE-INSPECTIONS (BY MT) WITH NO REPORTED INDICATIONS.

  - [ ][g] - THREE RE-INSPECTIONS (BY MT) WITH NO REPORTED (ID) INDICATIONS.

- WITH THE ISSUANCE OF INFORMATION NOTICE IN 85-86, OTHER UTILITIES HAVE PERFORMED PARTIAL INSPECTION (EITHER VISUAL, MT OR UT) OF THE GIRTH WELD NO. 6 WITHOUT REPORTED INDICATIONS.

Table 2.1-4 (Cont.)

2.2 Metallurgical Examination

Following the detection of indications in the girth welds, surface replicas were taken from the affected regions for preliminary site evaluation purposes. Boat samples were taken from the girth weld areas containing the indications for the purpose of conducting metallurgical investigations (Tables 2.2-1 to 2.2-3).

The boat sample from Steam Generator 24 contained a portion of a long crack initiated from the original ID surface and was identified as "boat 1". The sample from Steam Generator 22 contained a 1/2 in. long crack initiating from a surface ground during the previous refueling outage and was designated as "boat 2".

The evaluation included (Table 2.2-4):

- o Surface examination of the as-received boats by light optical and scanning electron microscopy techniques.
- o Metallographic examination of the boat sections containing the major cracked regions
- o Fractographic examinations of the freshly opened and Endoxed cracks by light optical and scanning electron microscopy techniques
- o High resolution transmission electron microscopy examination of replicas from the fracture face for evidence of fatigue striations
- o Hardness traverse measurement of the material microstructure containing the cracked regions
- o Chemistry evaluation of the crack deposits

The results of the surface examination of the as received boat samples showed oxide deposits and extensive surface pitting where the cracking was initiated. The surface pitting and the oxide deposits seen in boat 2 was significantly less severe than in boat 1. The cracking in boat 1 extended over the entire length of the boat while the cracking in boat 2 extended approximately over the middle third of the boat length. The surface examinations also showed the presence of a small crack on the bottom cut face of the boat 1 suggesting that the cracking extended as deep as the thickness of the boat. The results of the surface examinations are illustrated in Figures 2.2-1 and 2.2-2.

The results of the metallographic examinations (illustrated in Figures 2.2-3 to 2.2-10) showed evidence of multiple crack initiation sites originating from the surface pitting. The maximum size of the pits where cracking was initiated corresponded to approximately 25 mils. The cracking was initiated at the knee of the weld metal to base metal interface, where stress concentration due to geometric discontinuity is likely to be present. The cracks were extensively covered with oxide deposits all the way up to the crack tip regions. The cracking measured approximately 0.20 in. and 0.09 in. deep at their deepest locations in boats 1 and 2, respectively. The cracking was relatively straight and transgranular and disregarded the local microstructure of the material. No evidence of branching was seen in the cracks. For the most part, the heat affected zone microstructure where cracking was situated corresponded to quenched and tempered martensite-bainite aggregate. A hardness traverse measurements through the these regions showed a peak hardness level of 38 Rockwell "C" number suggesting that adequate toughness existed in the material. Boat 1 also revealed the presence of a tight secondary crack, below the main crack. Close examination of the crack however confirmed that the crack contained oxide deposits and hence is an extension of the main crack, perhaps connected at a different location along the crack length.

Fractographic examination of the freshly opened cracks by scanning electron microscopy (Figures 2.2-13 through 2.2-15) showed evidence of oxide deposits covering the entire fracture face. Energy dispersive X-ray analysis of the crack deposits confirmed the presence of copper, sulfur and zinc at the crack mouth regions where pitting was seen (Figures 2.2-16 through 2.2-18). The remainder of the crack however is free from any aggressive elements. Light optical fractographic examination of the freshly opened and Endoxed fracture faces showed clear evidence of crack initiation sites corresponding to pits on the boat surface with typical thumb nail patterns (Figures 2.2-11 and 2.2-12). Evidence of numerous beach marks were seen at the crack-tip regions suggesting that changes in the load and/or environment occurred during the life of the crack. Scanning electron fractographic examination of the Endoxed cracks confirmed the presence of finely spaced crack arrest lines and corroded base metal.

Replica transmission electron microscopy examination of the crack tip regions showed some areas resembling the appearance of fatigue striations on the freshly opened and Endoxed faces of the subsurface crack seen in boat #1 (Figures 2.2-19 and 2.2-20). The formation of the oxides in the crack probably consumed much of the evidence of fine fatigue striations.

The presence of heavy oxide deposits, pitting and multiple crack initiation sites seen at the surface suggest that crack initiation may have occurred by surface pitting. Since the boat sample from SG 22 was taken from a surface ground during the previous outage, the surface pitting seen in boat #2 must have been introduced during the last operating cycle. The generally straight nature of the cracks with no evidence of branching, suggests that the crack progression may have occurred under the influence of loads axial to the steam generator. The presence of numerous crack arrest lines on the fracture face suggests that cracking may have occurred under the influence of intermittant or cyclic loads. The presence of heavy oxide deposits and corrosive attack seen on the entire fracture face confirms the strong role of corrosion in enhancing the crack growth process.

Based on the overall results of the evaluations, it is concluded (Table 2.2-5) that cracking in the steam generator girth weld and nozzle area most likely occurred by corrosion fatigue mechanism. The presence of corrosive elements and stress concentration at the knee of the weld joint contributed to pitting and crack initiation.

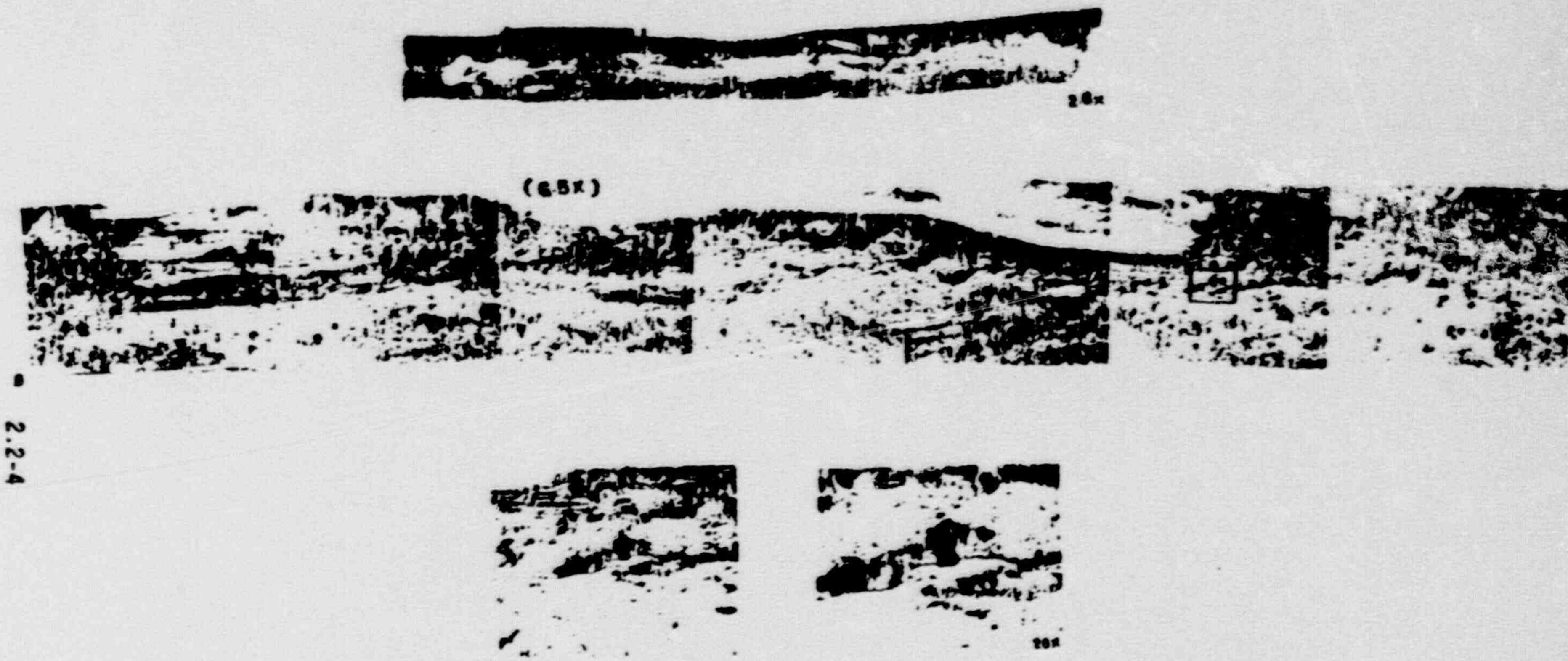


Figure 2.2-1 As-received surface appearance of the Boat 1 sample from Steam Generator 24 girth weld , illustrating the surface pitting and cracking seen on the ID surface.

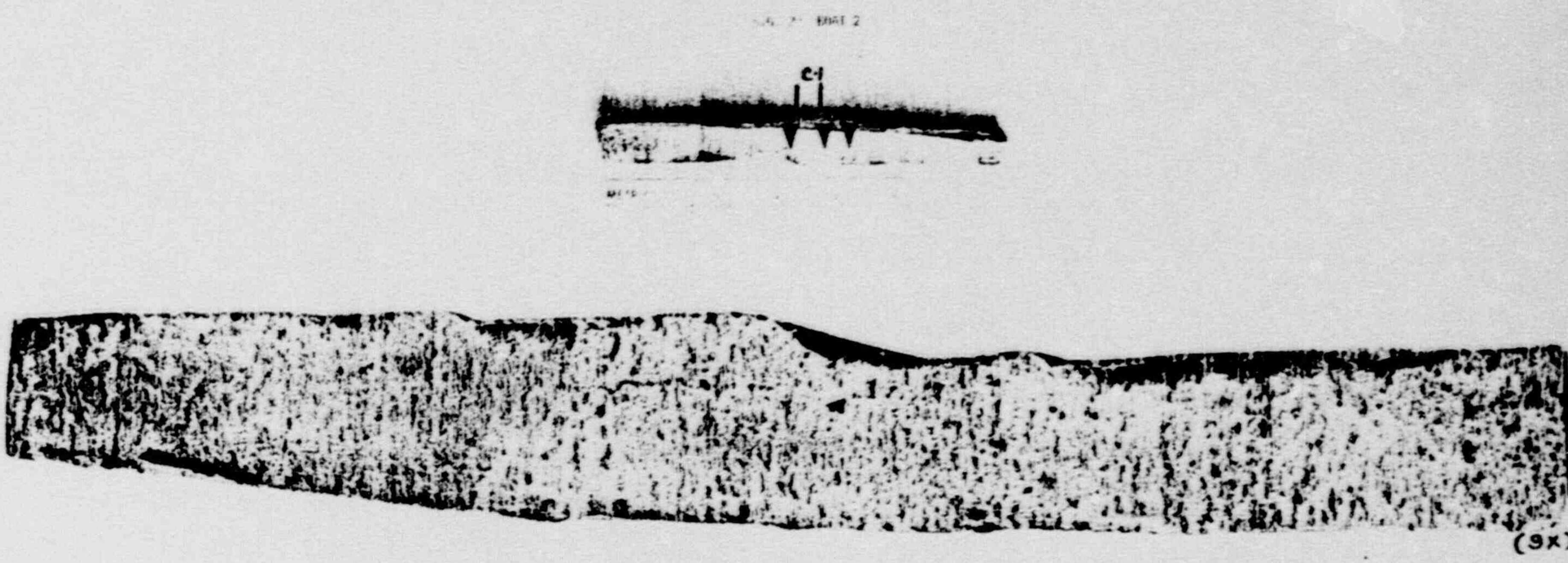
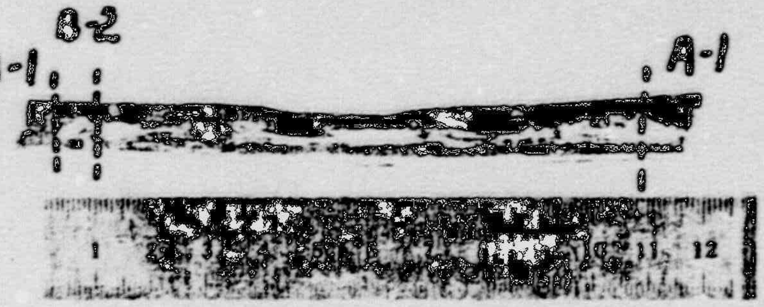
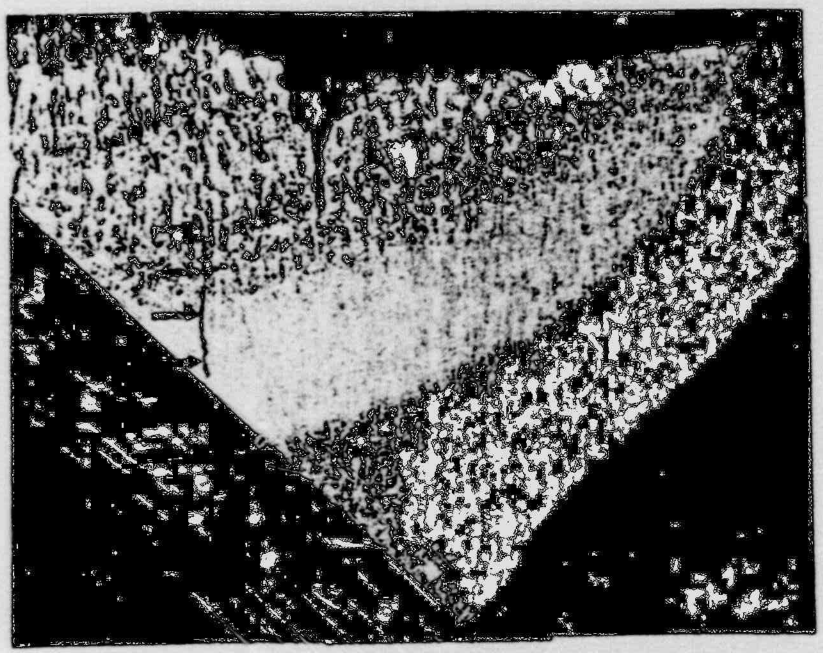
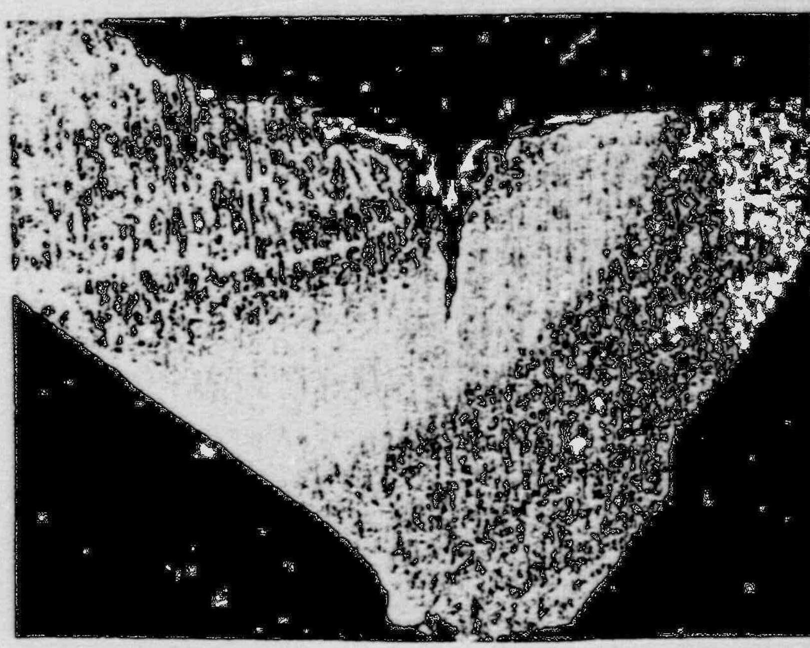


Figure 2.2-2 As-received surface appearance of the Boat 2 sample from Steam Generator 22 girth weld, illustrating the surface pitting and cracking seen on the ID surface.





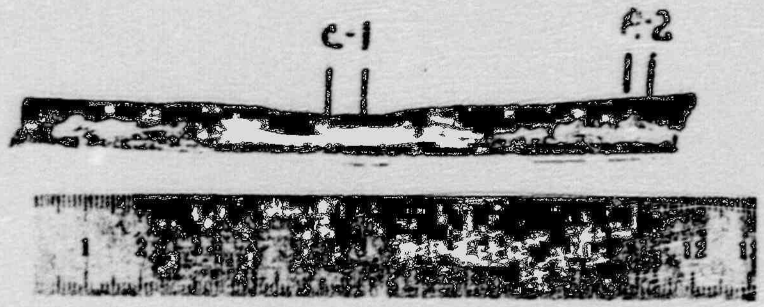
BOAT -1
SECTION B-2
15x

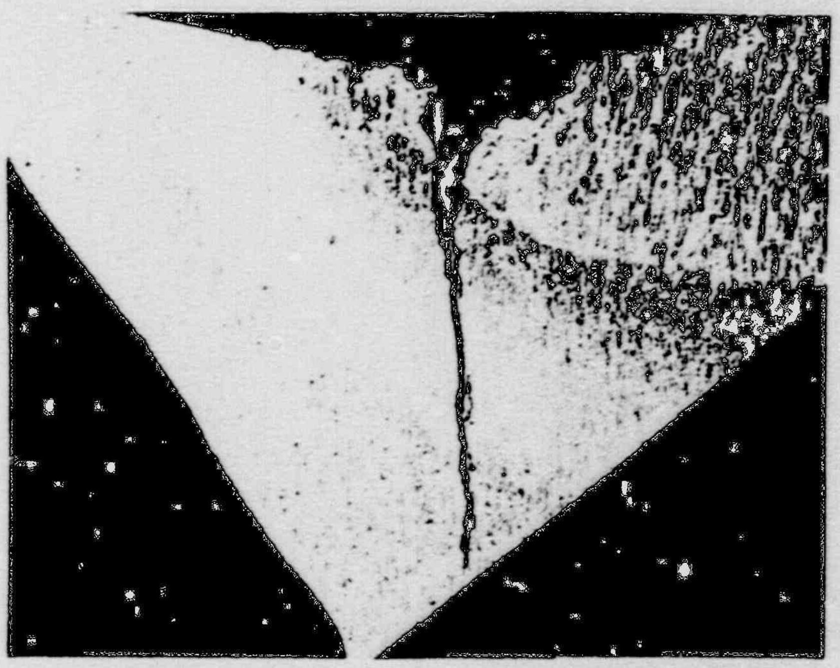


BOAT -1
SECTION A-1
15x

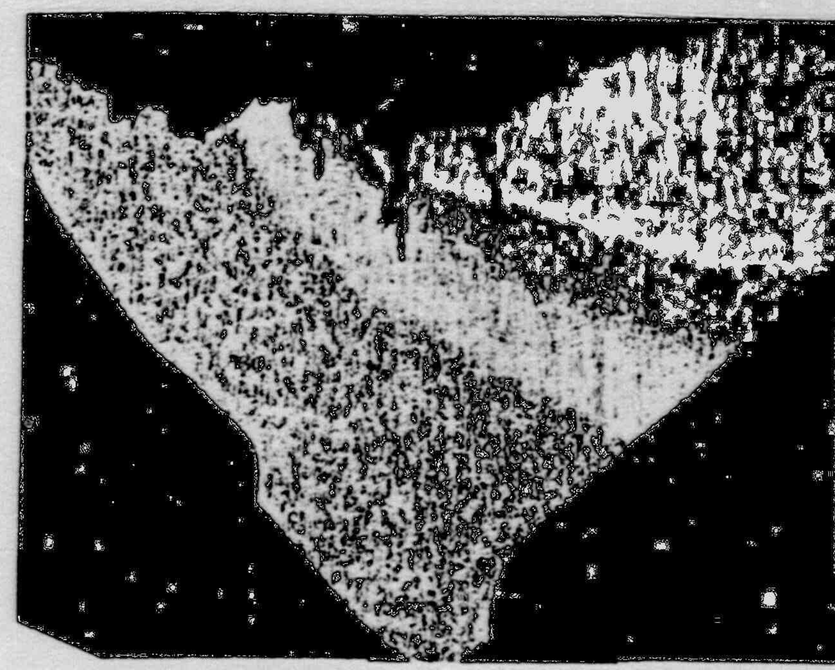
Figure 2.2-3 Metallographic examination results illustrating the cracking morphology and microstructure seen in Boat 1.

S.G. 24 BOAT 1



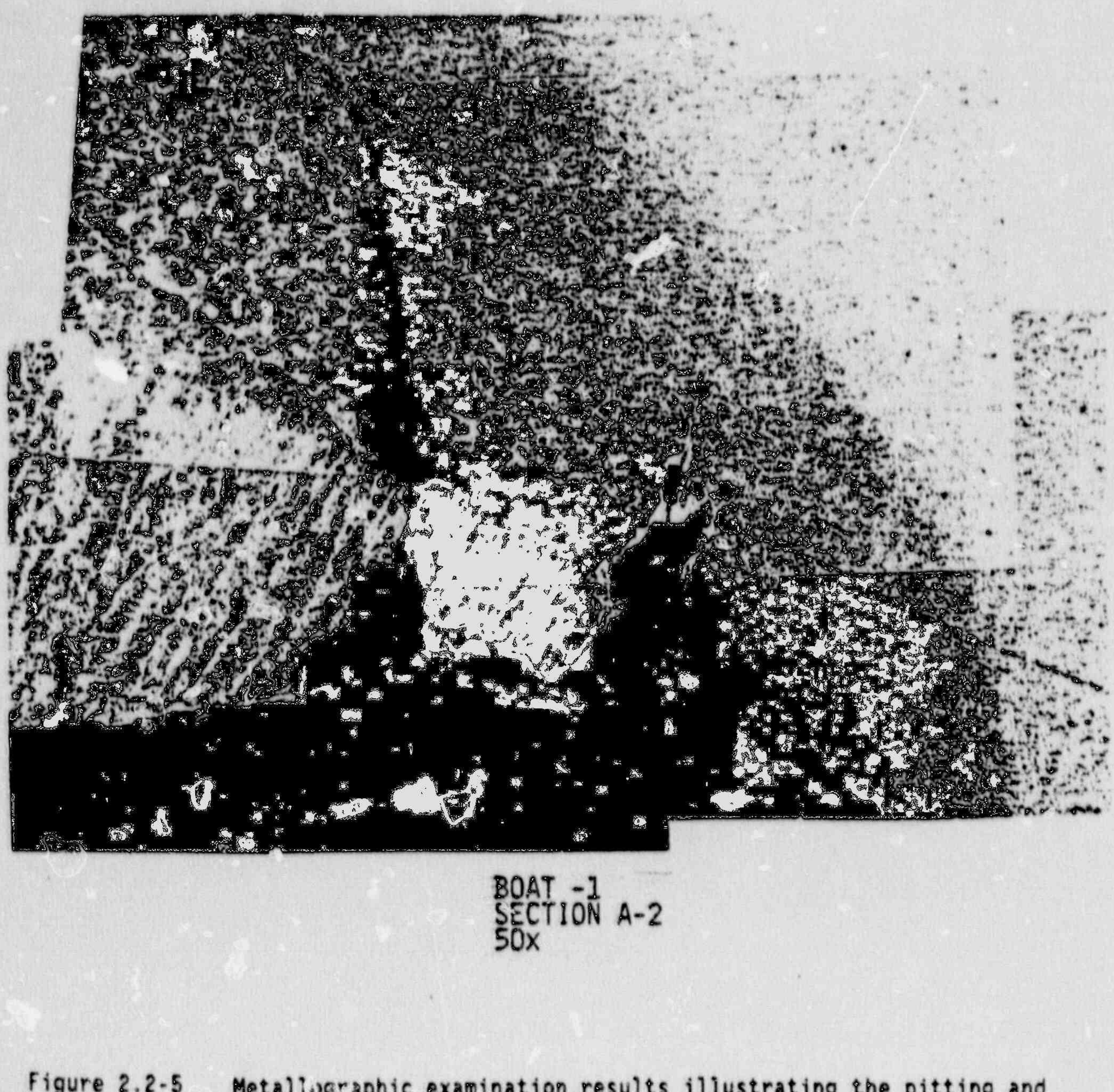


C-1 14x



A-2 14x

Figure 2.2-4 Metallographic examination results illustrating the cracking morphology and microstructure seen in Boat 1.



BOAT -1
SECTION A-2
50x

Figure 2.2-5 Metallographic examination results illustrating the pitting and oxide deposits at the crack initiation in Boat 1.

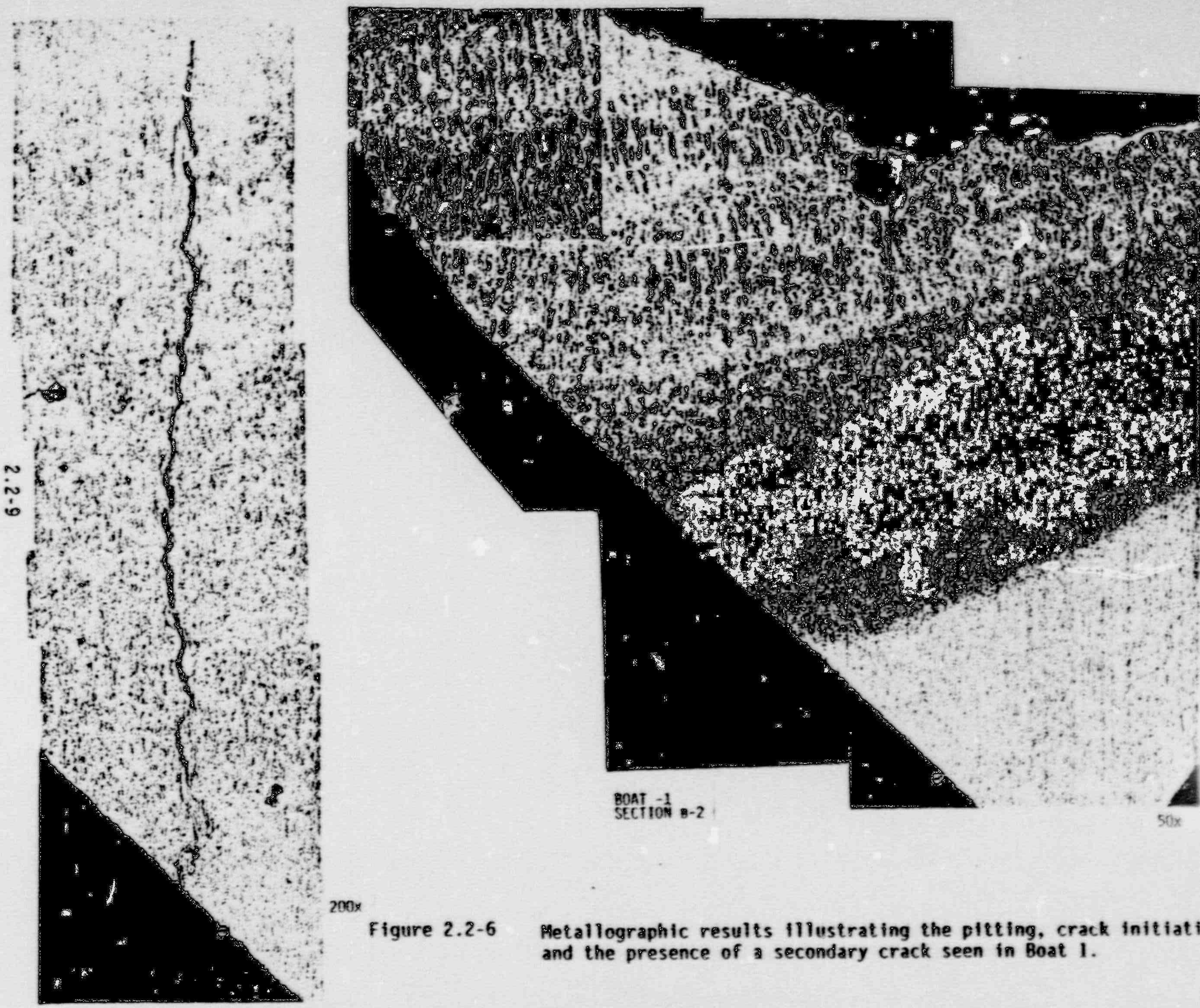


Figure 2.2-6 Metallographic results illustrating the pitting, crack initiation and the presence of a secondary crack seen in Boat 1.

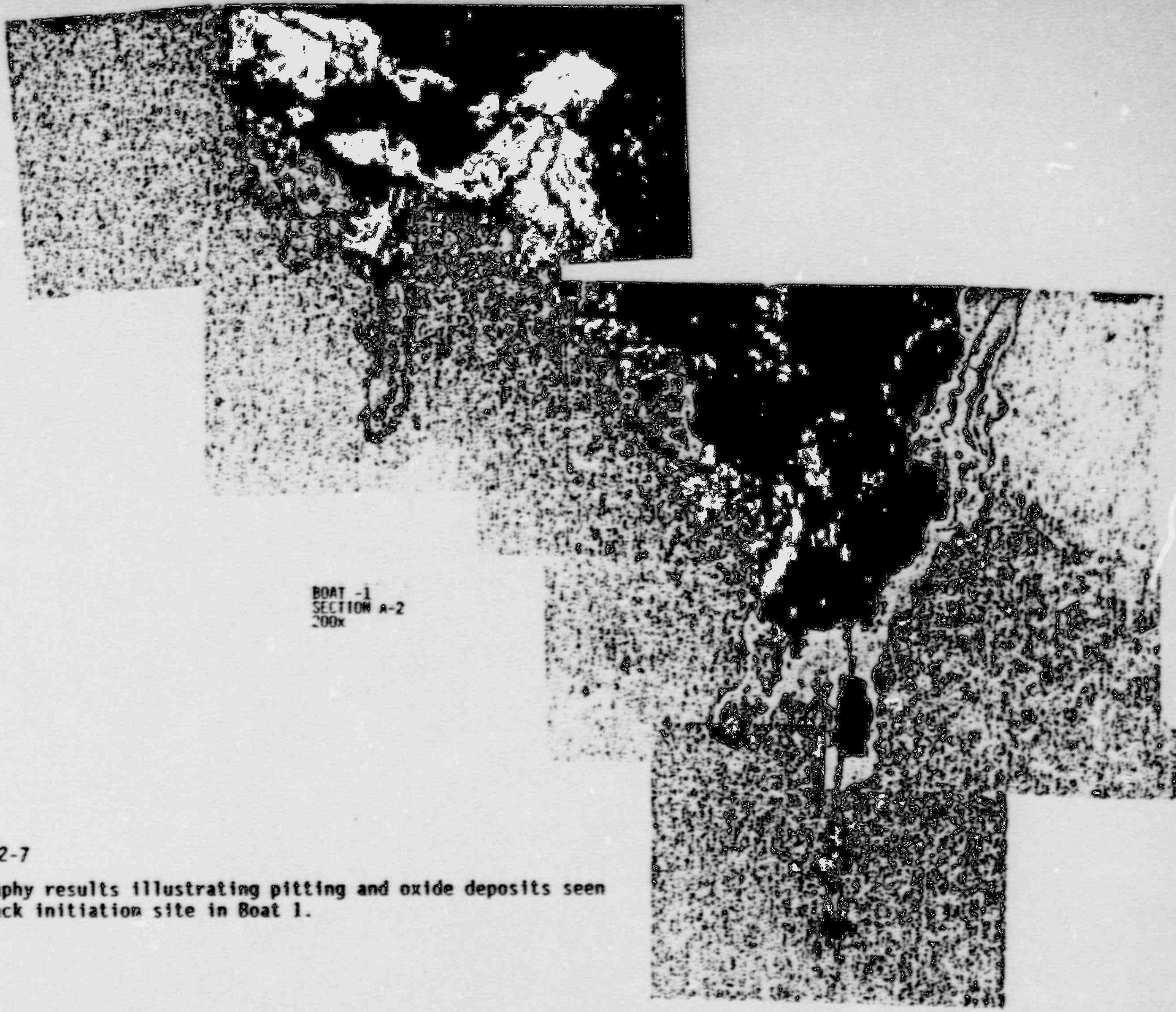


Figure 2.2-7

Metallography results illustrating pitting and oxide deposits seen at the crack initiation site in Boat 1.

Figure 2.2-8 Metallography results illustrating the pitting and oxide deposits seen at the crack initiation site in Boat 1.

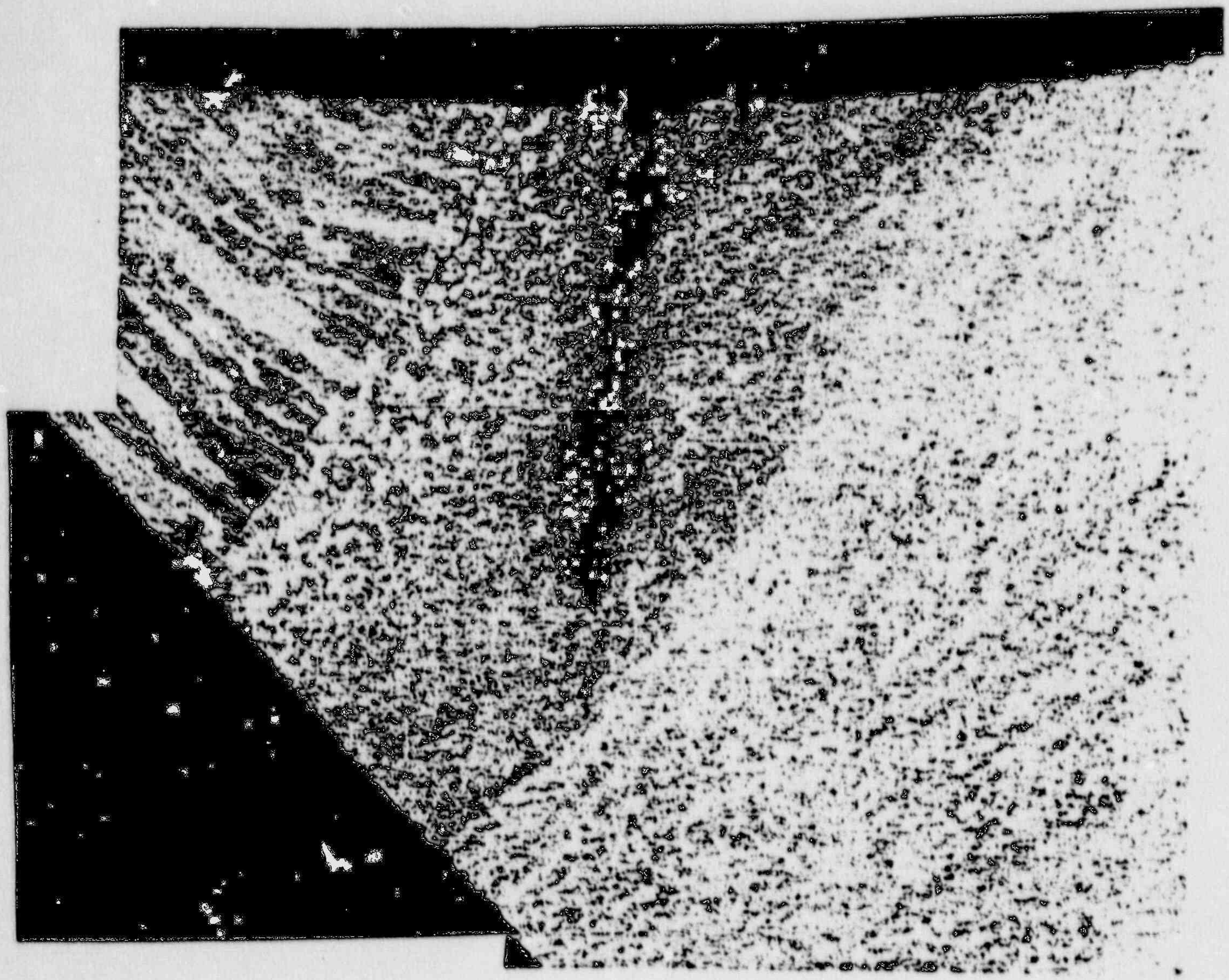


Figure 2.2-9 Metallography results illustrating the cracking morphology and material microstructure seen in Boat 2.

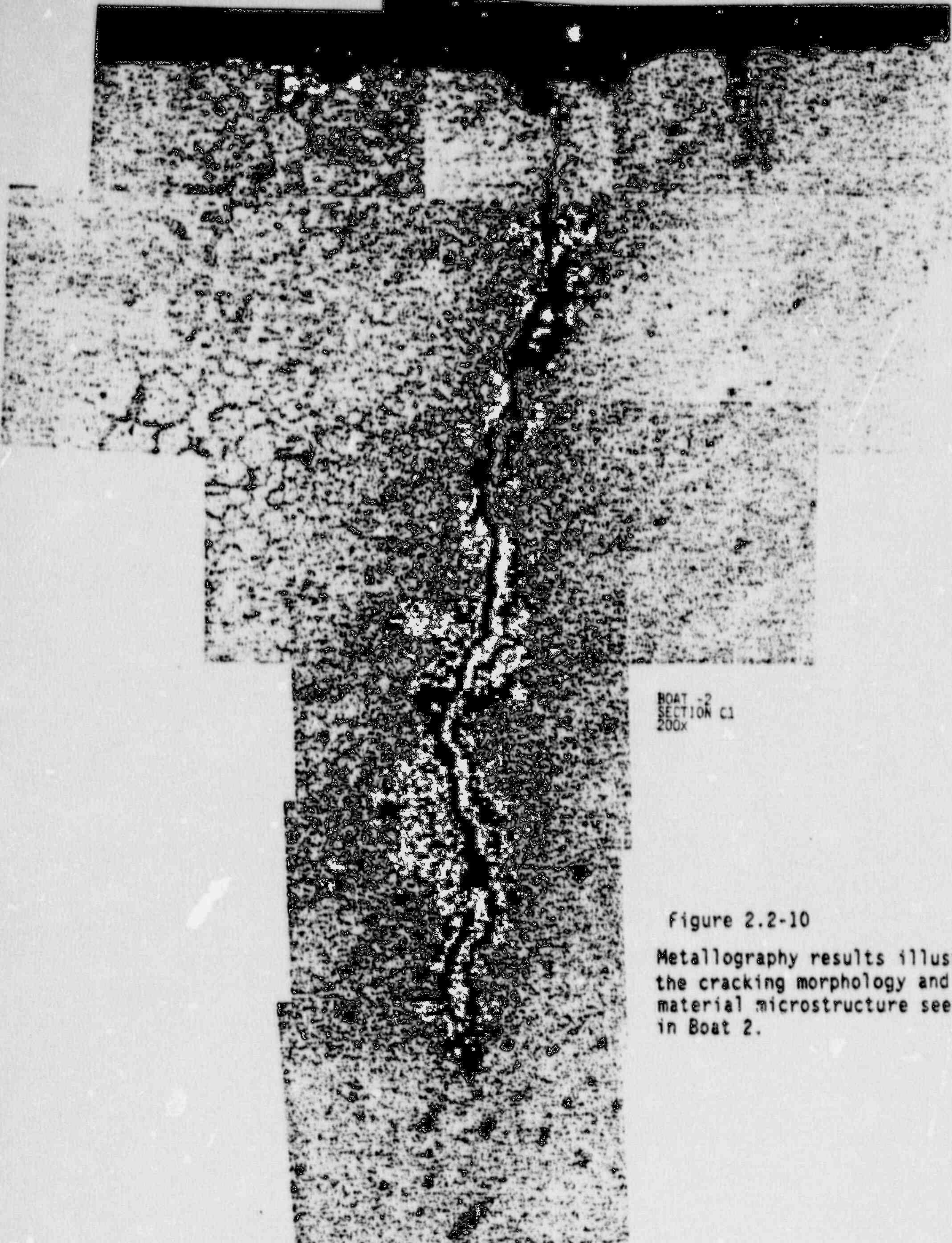


Figure 2.2-10

Metallography results illustrating the cracking morphology and material microstructure seen in Boat 2.

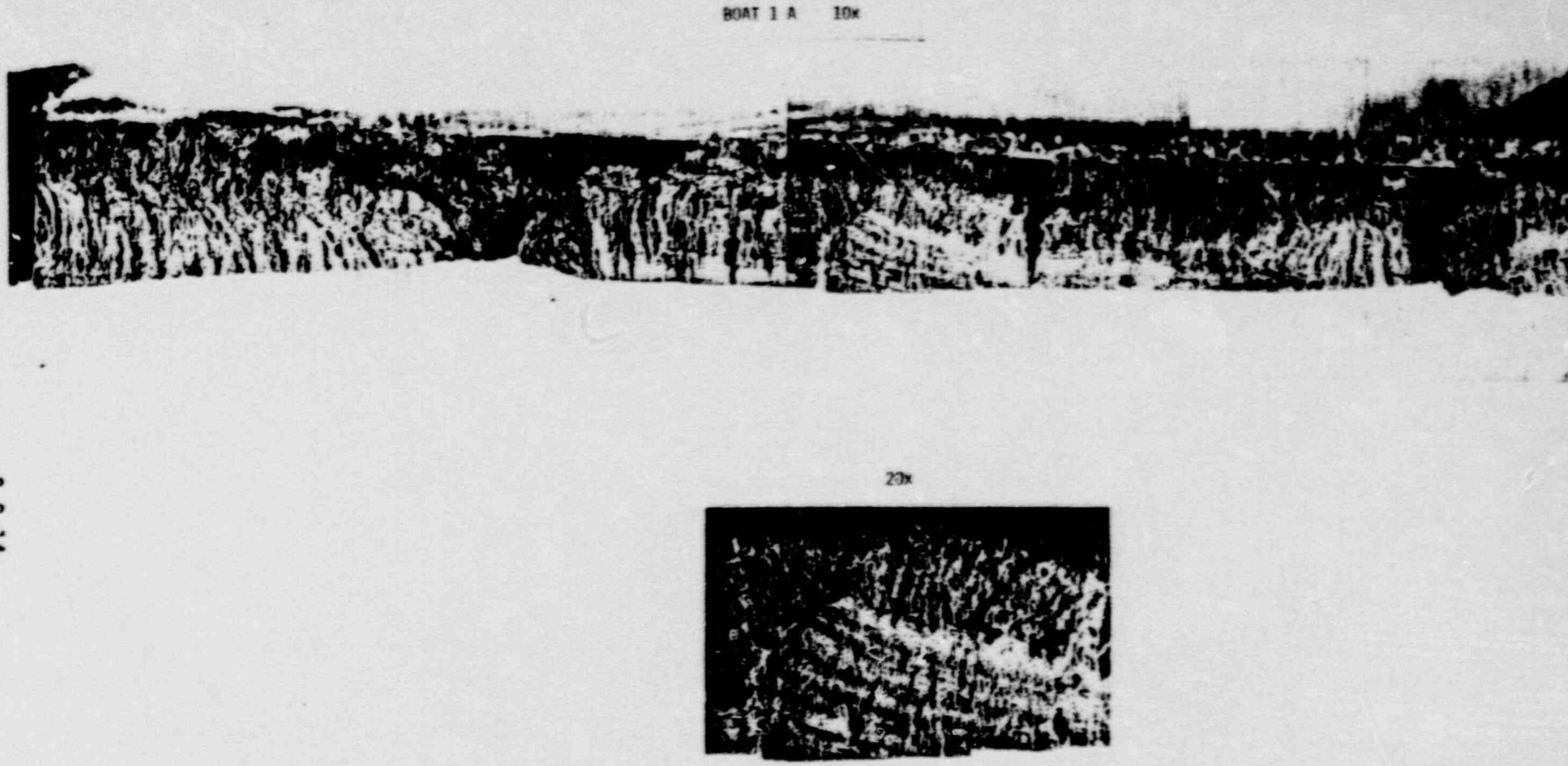


Figure 2.2-11 Light optical fractography results illustrating the beach marks seen in the endoxed fracture face in Boat 1.

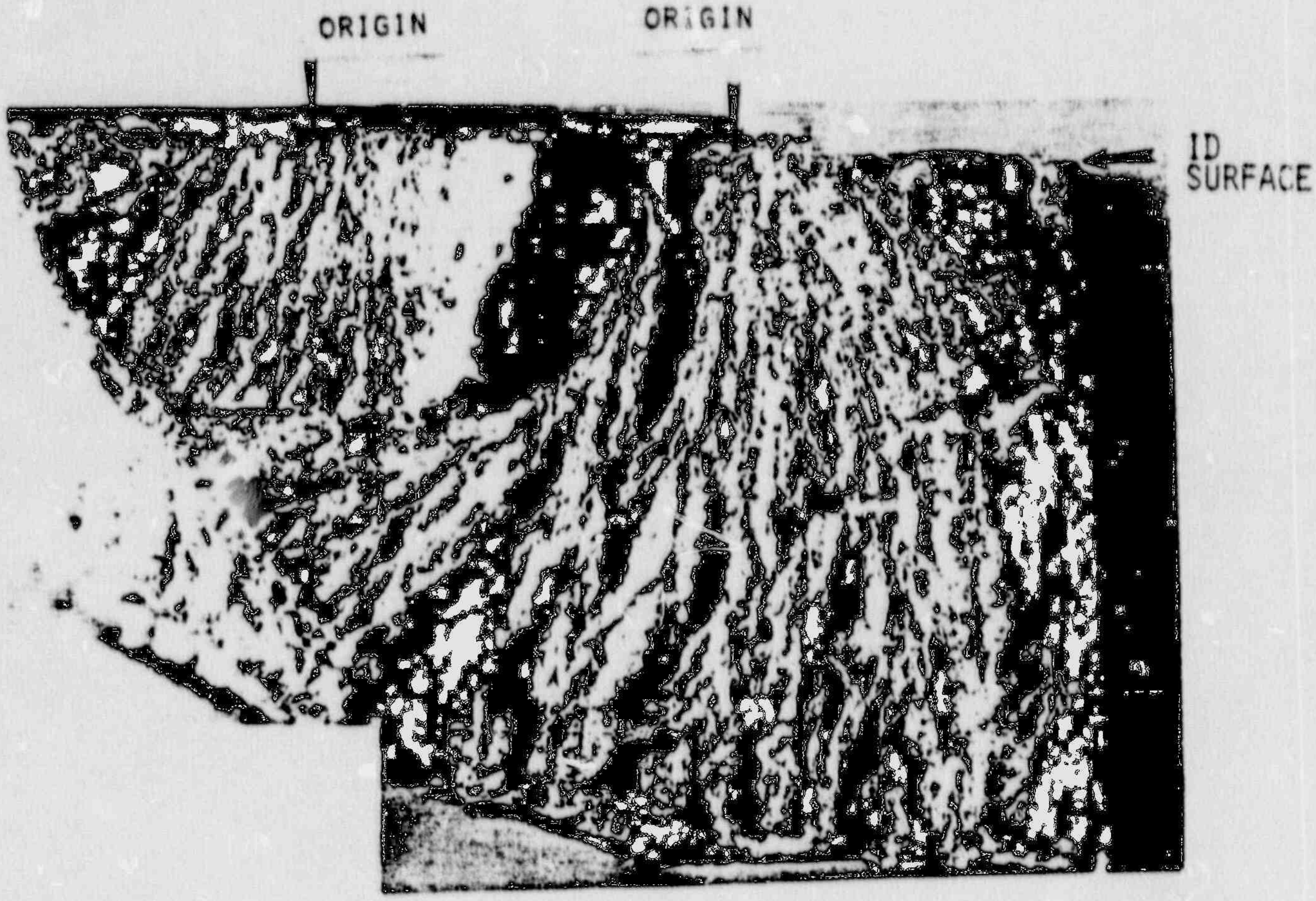


Figure 2.2-12 Light optical fractograph illustrating the fracture morphology seen in Boat 2.

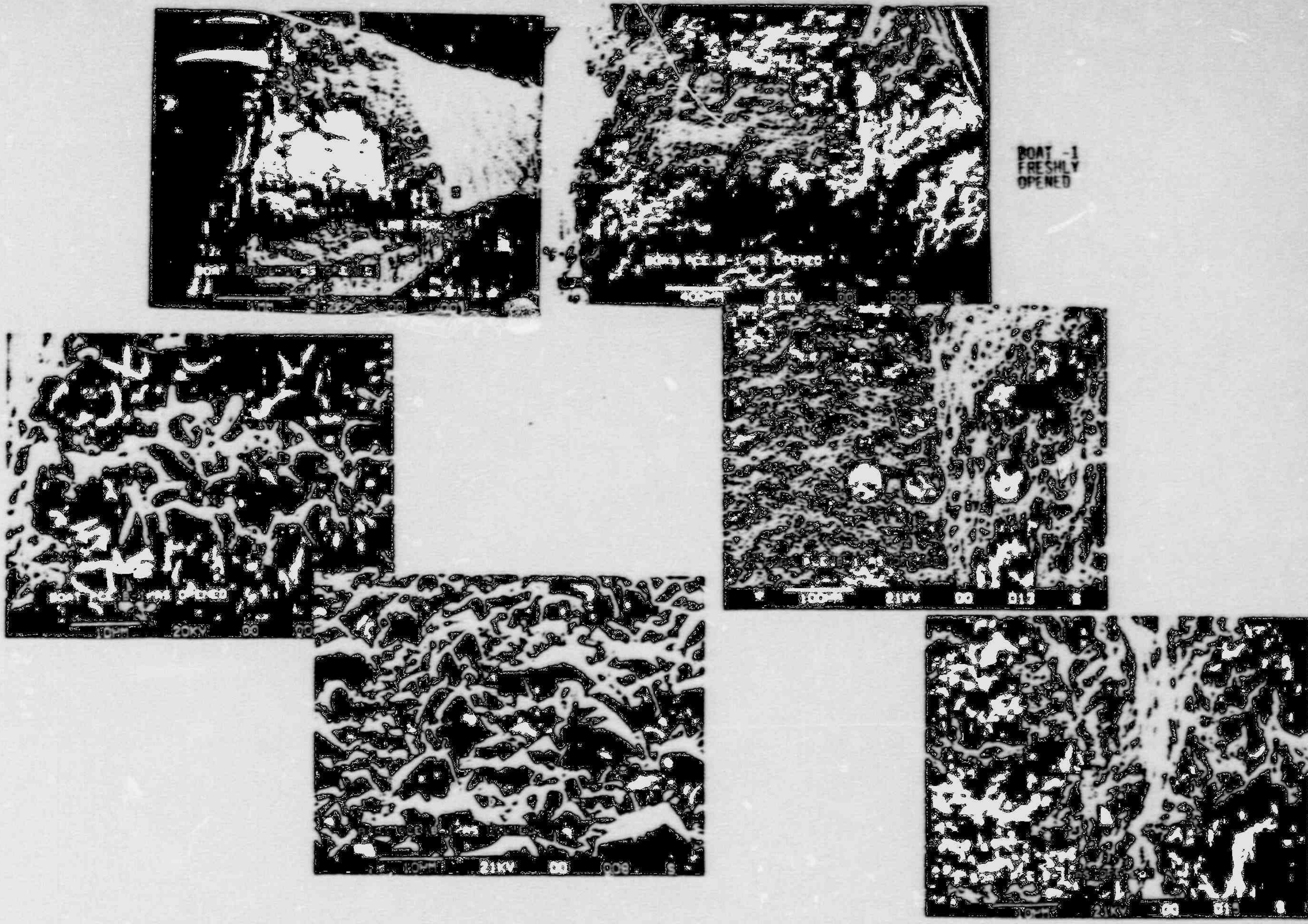
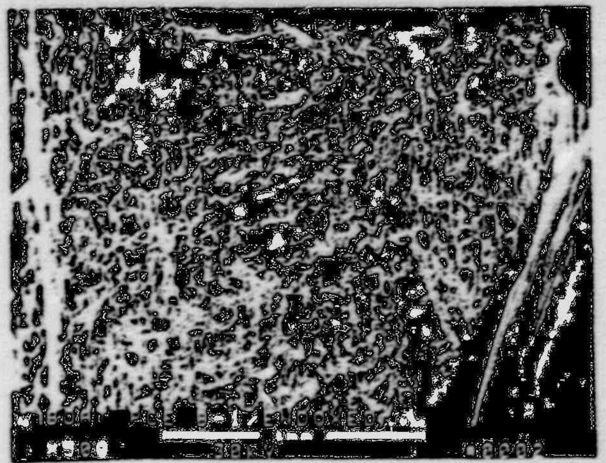
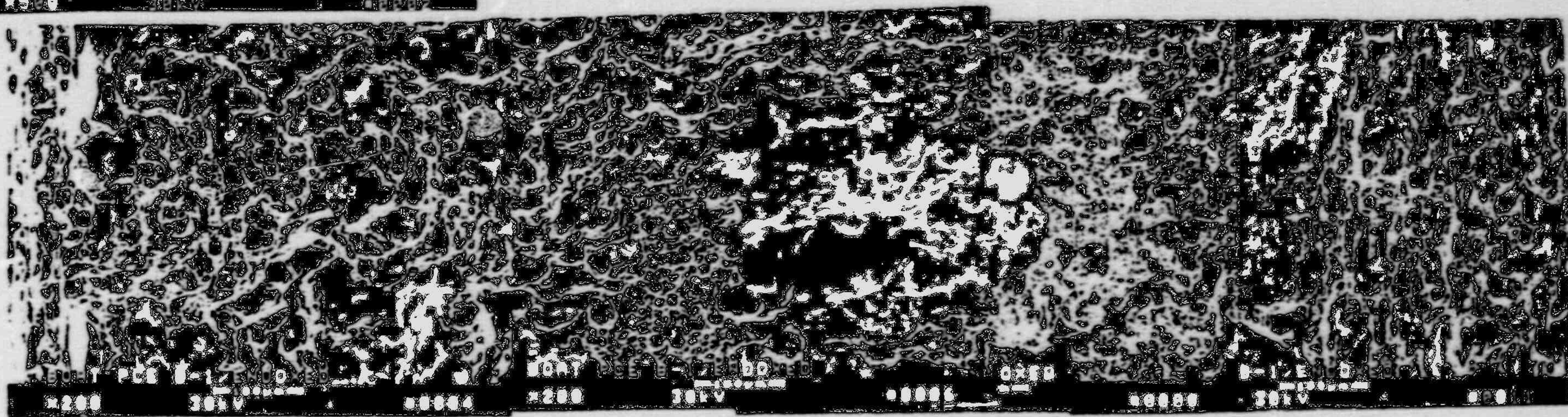


Figure 2.2-13 Scanning electron fractography results of the freshly opened crack in Boat 1 illustrating the oxide covered service fracture and dimpled laboratory fracture.



ENDOXED
FRACTURE FACE
SECTION B-1
BOAT -1



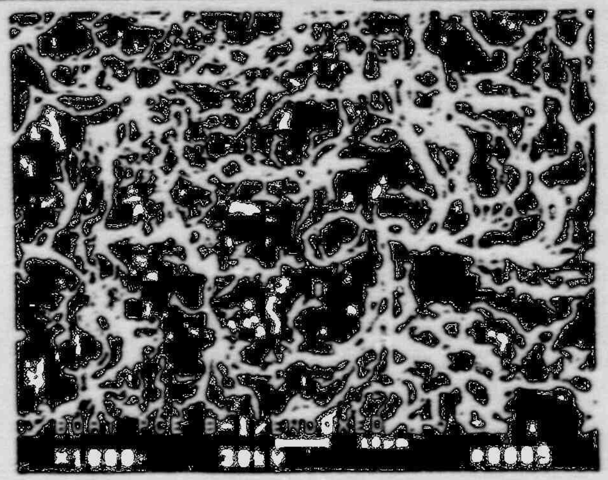
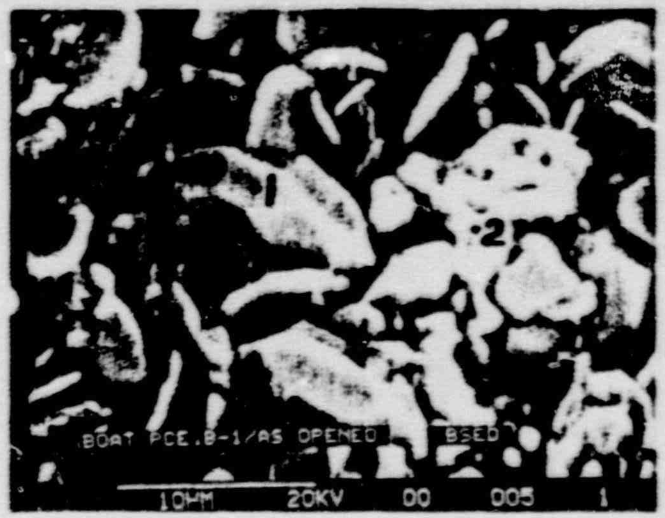


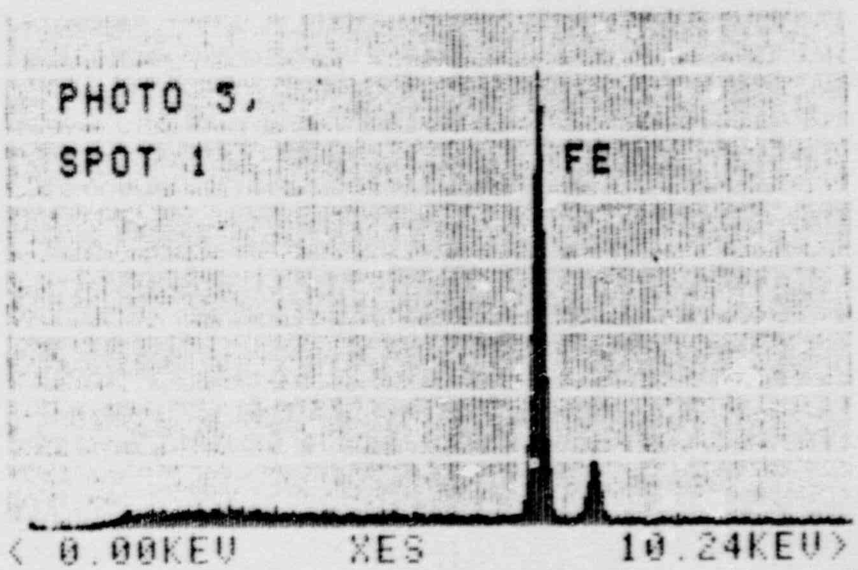
Figure 2.2-14

Scanning electron fractographs illustrating the morphology of endoxed field fracture face in Boat 1

Figure 2.2-15 Scanning electron fractograph of the endoxed fracture face in Boat 1 illustrating the presence of fatigue striations.



BOAT -1
CRACK MOUTH
CHEMISTRY



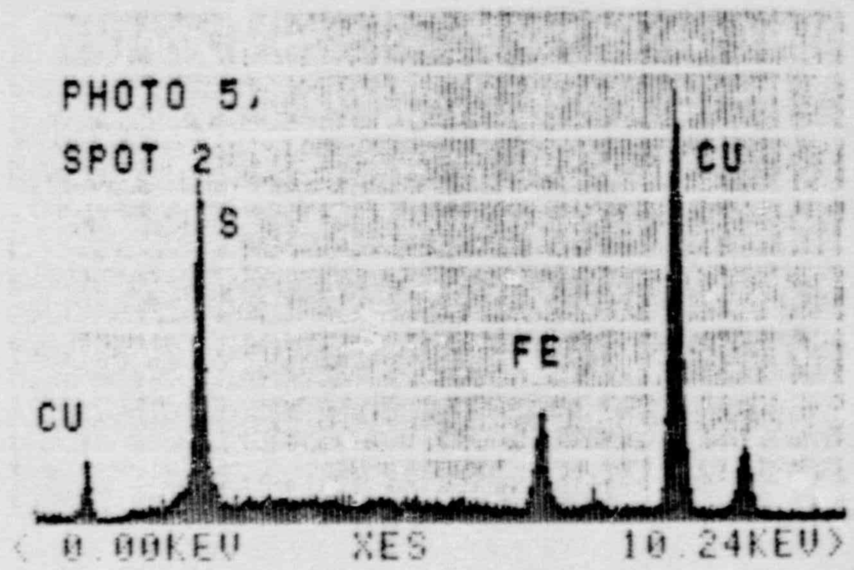
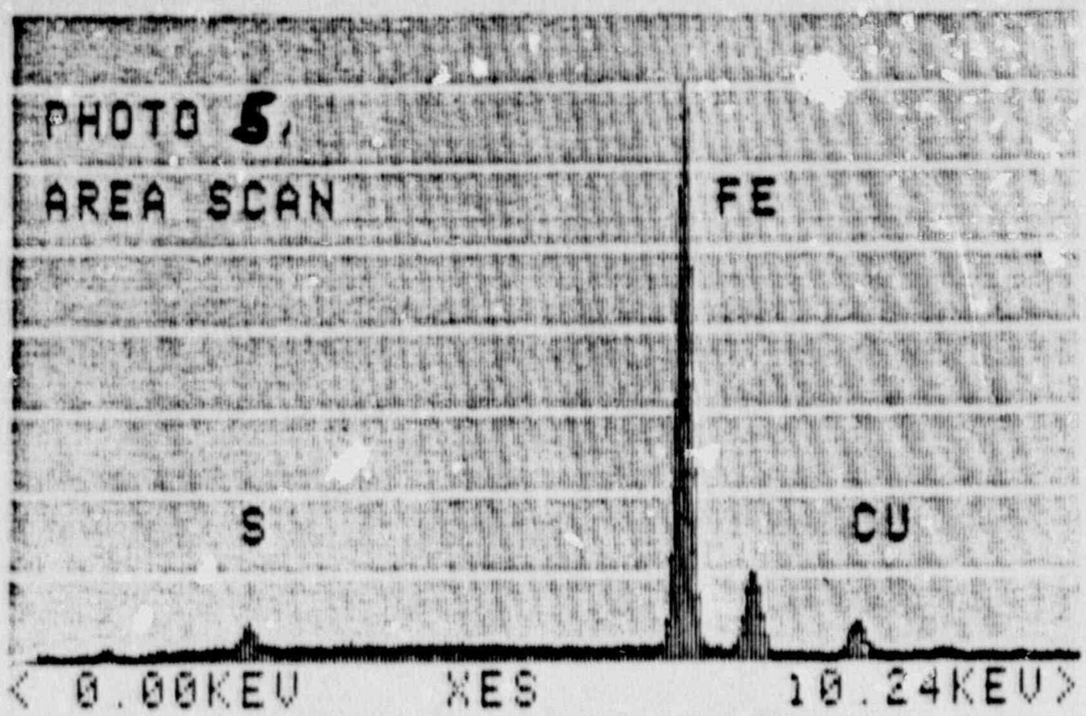
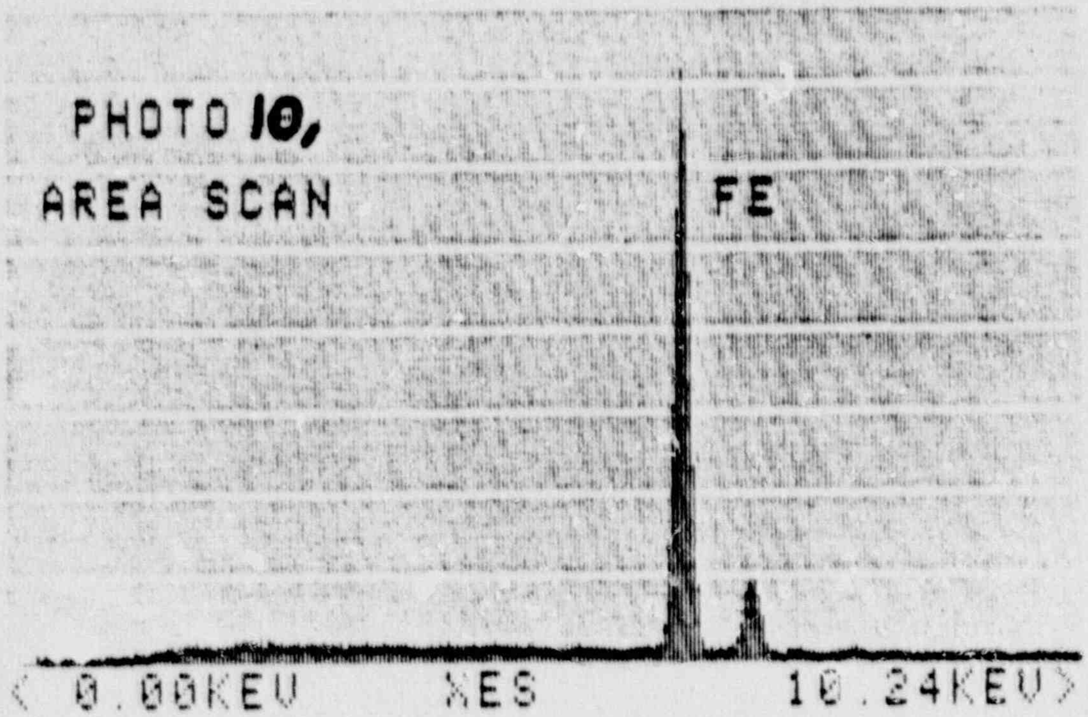


Figure 2.2-16 Energy dispersive X-ray analysis results of the crack deposits in Boat 1.



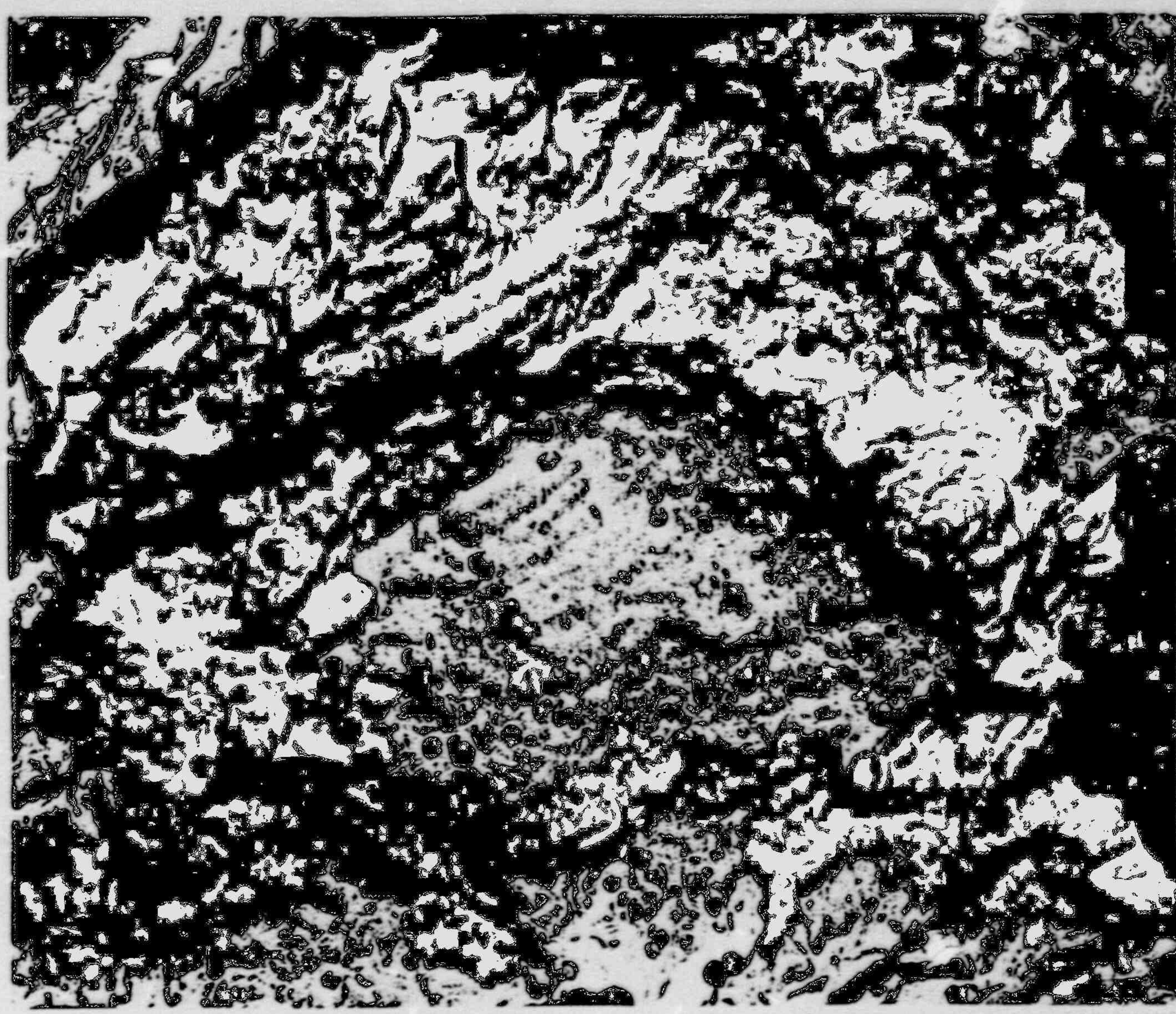
BOAT 1
CRACK MOUTH



BOAT 1
CRACK TIP

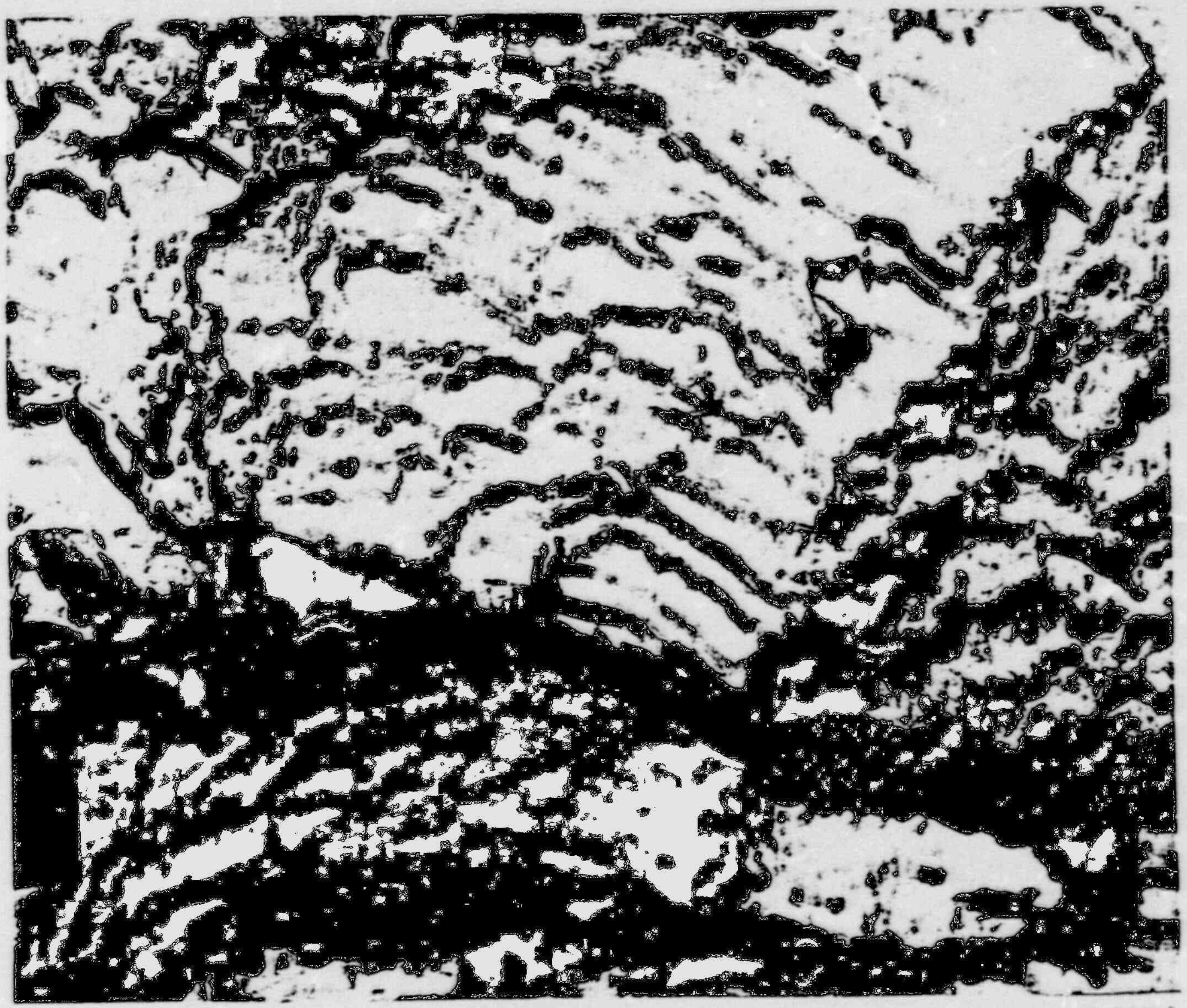
Figure 2.2-17 Energy dispersive X-ray analysis results of the crack deposits in Boat 1.

Figure 2.2-18 Energy dispersive X-ray analysis results of the crack deposits in Boat 2.



(44,000X)

Figure 2.2-19 Replica transmission electron fractograph illustrating the presence of fatigue striations at the crack-tip.



(44,000X)

Figure 2.2-20 Replica transmission electron fractograph illustrating the presence of fatigue striations at the crack-tip.

METALLURGICAL EXAMINATION OF BOAT SAMPLES

OBJECTIVES:

- TO ESTABLISH THE CAUSE AND MECHANISM OF CRACKING
- TO DEVELOP INFORMATION THAT WOULD BE HELPFUL IN FORMING CORRECTIVE ACTIONS

Table 2.2-1

CRACK DEPTH OF POLISHED BOAT SAMPLES

SG-24 BOAT #1	INCHES	MM	COMMENTS
A-1	0.0714	1.81	
A-2	0.0714	1.81	
B-2	0.0536	1.36	
B-2	0.0536	1.36	SECONDARY CRACK
C-1	0.196	4.99	WENT TO END OF BOAT SAMPLE. POSSIBLY FARTHER.
SG-22 BOAT #2			
C-1	0.0875	2.22	FIRST POLISH
C-1	0.065	1.55	SECOND POLISH

Table 2.2-2

SAMPLES

• BOAT 1	SG #24	VIRGIN ID SURFACE
• BOAT 2	SG #22	PREVIOUSLY GROUND-OUT SURFACE

Table 2.2-3

MAJOR TASKS

- O Surface Examinations
- O Metallographic Examinations
- O Fractographic Examinations
  - Light Optical
  - Scanning Electron
- O High Resolution Transmission Electron Microscopy Examination of Replicas
- O Chemistry Evaluation of Crack Deposits
- O Hardness Traverse Measurements

Table 2.2-4

CONCLUSIONS

- O CRACKING IN THE STEAM GENERATOR GIRTH WELDS WAS CAUSED BY CORROSION FATIGUE MECHANISM

- O SURFACE PITTING AND STRESS CONCENTRATION AT THE KNEE OF THE WELD JOINT CONTRIBUTED TO CRACK INITIATION

Table ?.2-5

2.3 Indian Point 2 Experience (1989)

MT examination was performed on the girth weld inside circumference surface on all four steam generators. The process was performed in accordance with Westinghouse Nondestructive Examination Procedure NDE-310, Rev. 0. This procedure is for examination of ferromagnetic materials and weldments at less than 600 degrees F utilizing dry powder magnetic particle examination techniques, Yoke Method. This procedure is prepared based on requirements in the ASME Boiler and Pressure Vessel Code, Section III and V.

Examination results indicated that the extent of the indications found varied between steam generators, with No. 22 exhibiting the highest number of recordable indications (49) and No. 21 the least (5). The following table summarizes the number of indications found per steam generator.

Steam Generators	Number of Indications
21	5
22	49
23	15
24	6

A detailed repair procedure was prepared for removal of the all surface indications by grinding. To assist in record keeping of each indication, the girth weld region was divided into 12 zones per Figure 2.3-1. A baseline MT examination was performed to document the total number of indications, locating each indication horizontally within each zone and vertically relative to the weld centerline.

The repair process for removal of the indications involved controlled grinding to a specific depth (typically, 0.25 inches), followed by a VT or MT inspection. This process was continued until the surface indication was removed. Once the indication was verified as MT clear, the adjacent metal was then blended to a 2:1 taper (minimum) down to the base of the excavation.

This surface contouring was performed to assure conformance with analyzed geometry for reducing stress concentrations at all ground locations. After all contouring was completed, all ground surfaces were given a final MT inspection to assure the MT clear condition. Table 2.3-1 lists the locations and sizes of the indications found and removed.

Tables 2.3-2, 2.3-3, 2.3-4, 2.3-5 and 2.3-6 provide a comparison between the 1989 experience to that of the 1987 experience of the number of indications per zone and the maximum depth of metal removed to clear the indications. For all four steam generators, the data reveals that the number of indications in 1989 (76 total) were significantly less than those revealed in 1987 (291 total). Twenty-five zones had no indications (by MT inspection) in 1989 whereas only 6 zones had no indications in 1987. Also compared on a zone by zone basis (1989 to 1987) were the maximum depths of grinding required to remove an indication. Of 48 total zones (all four steam generators), only 12 zones required deeper depth of grinding to remove indictions in 1989 when compared to the original depth of grinds from 1987. The maximum depth of grind for 1989, 1.42 inches, occurred in Zone 7 of steam generator No. 22. The average depth of grinding (all four steam generators) for 1989 was 0.24 inches versus an average of 0.35 inch depth for 1987 per Table 2.3-7. Table 2.3-8 provides a summary of the number of indications, maximum depth of grind, and average depth of grind of the 1989 data relative to the 1987 data.

Figure 2.3-2 depicts the depth of final grindout in terms of the frequency of occurrence of various depths for each steam generator. In terms of final depth, the figure shows that 22 is unique when compared to the other steam generators since the eight deepest grindouts occurred in 22.

Figure 2.3-3 depicts the depth of indication growth during one fuel cycle in terms of the frequency of occurrence of various depths for each steam generator. In terms of maximum growth rate, the figure shows that SG 22 is again unique when compared to the other steam generator since the eleven largest crack growth rates occurred only in SG 22.

Figures 2.3-4, 2.3-5, 2.3-6, and 2.3-7 provide a comparison of location of the indications (for both 1989 and 1987) relative to the feedwater nozzle, feedring and J-nozzle orientation. No conclusive correlation was noted between indications and distribution of J-nozzles, hot or cold leg location, or orientation of the feedring sections as per Tables 2.3-9 and 2.3-10.
[ ]g

A review of the material properties and fabrication history of the steam generator girth welds was made. Chemical analysis and mechanical properties are summarized in Table 2.3-11 and 2.3-12, respectively. All values were within acceptable limits.

Girth Weld No. 6 for the Indian Point Unit 2 steam generators was fabricated by field welding the inside surface and then back gouging or grinding and welding from the outside. Figure 2.3-26 is a general schematic showing the EV steps for the upper shell/cone section of the steam generators.

The weld records indicated that the welds were deposited using E8018 filler and post weld heat treated using qualified procedures that satisfied the requirements of the ASME III 1965/S 1966 code of construction. Per Section III requirements, the alignment at the edges of the shell shall be such that the maximum offset does not exceed 29/64 in. On-site fit-up was used to obtain "best minimum offset condition". Records available do not indicate results of the maximum allowable offset, however, no nonconformances were uncovered. It was common practice to jack the upper shell, up to one inch in diameter, in order to meet the offset guidelines. The stresses resulting from jacking or cold spreading were relieved during subsequent post weld heat treatment of the closure joint. All offsets were required to be flared in a 3:1 taper over the width of the finished weld, and if necessary, additional weld metal was added beyond what would otherwise be the edge of the weld.

The heat treat records for weld #6 were reviewed and found to meet procedure requirements. Weld procedures in place at the time of the field weld required a minimum preheat of 225°F and a maximum interpass temperature of 500°F. The ID of the closure weld was completed, followed by chipping and grinding to remove any unfused root section of weld from the OD. The OD weld was then made. The post weld stress relief was performed per Section III requirements. The maximum rate of heating was as specified in the procedure, 100°F/hr. The soak temperature and time was determined by the minimum temperature attained by any one of the thermocouples on the weld when the maximum temperature attained was 1150°F. The minimum hold time/temperature limits were as follows:

Min Temp	When Max Temp	Hold Time
1100°F	1150°F	3 1/2 hrs
1050°F	1150°F	7 hrs
1000°F	1100°F	10 1/2 hrs

Table 2.3-13 summarizes the heat treat requirements and records for the various steam generators at Indian Point 2. As can be seen by the data, all limits were satisfied.

Additionally, an earlier review of the closure weld records indicated that there were no nonconformances noted for either NDE inspections or weld repairs. Code required NDE was performed, but documentation is not currently available to determine whether the MT was performed before or after post weld heat treatment.

ZONE IDENTIFICATION

(FOR MT INSPECTIONS AND SUBSEQUENT GRINDING OPERATIONS)

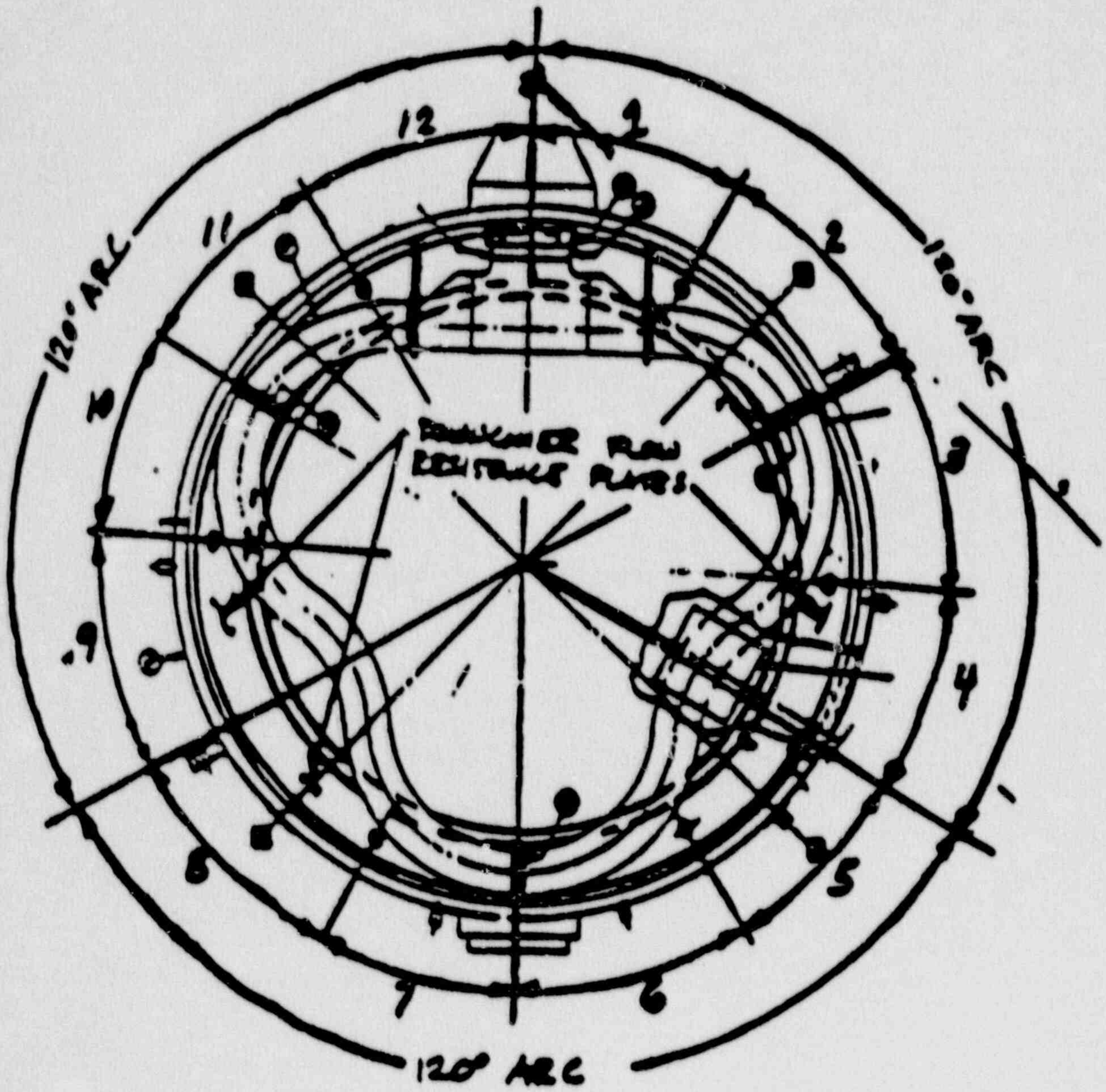
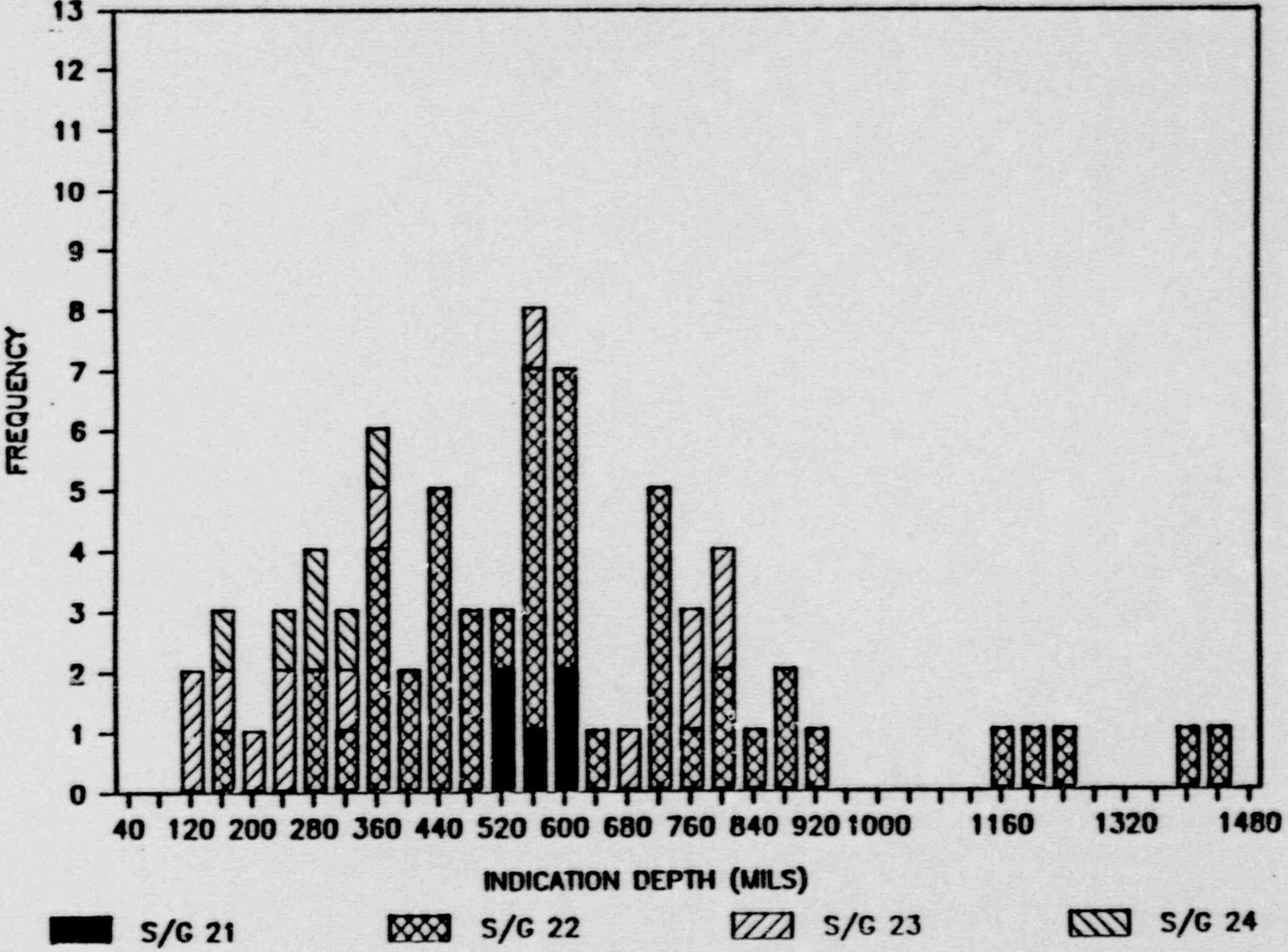


Figure 2.3-1

INDIAN POINT STATION UNIT 2
STEAM GENERATOR GIRTH WELD
1989 FINAL DEPTH

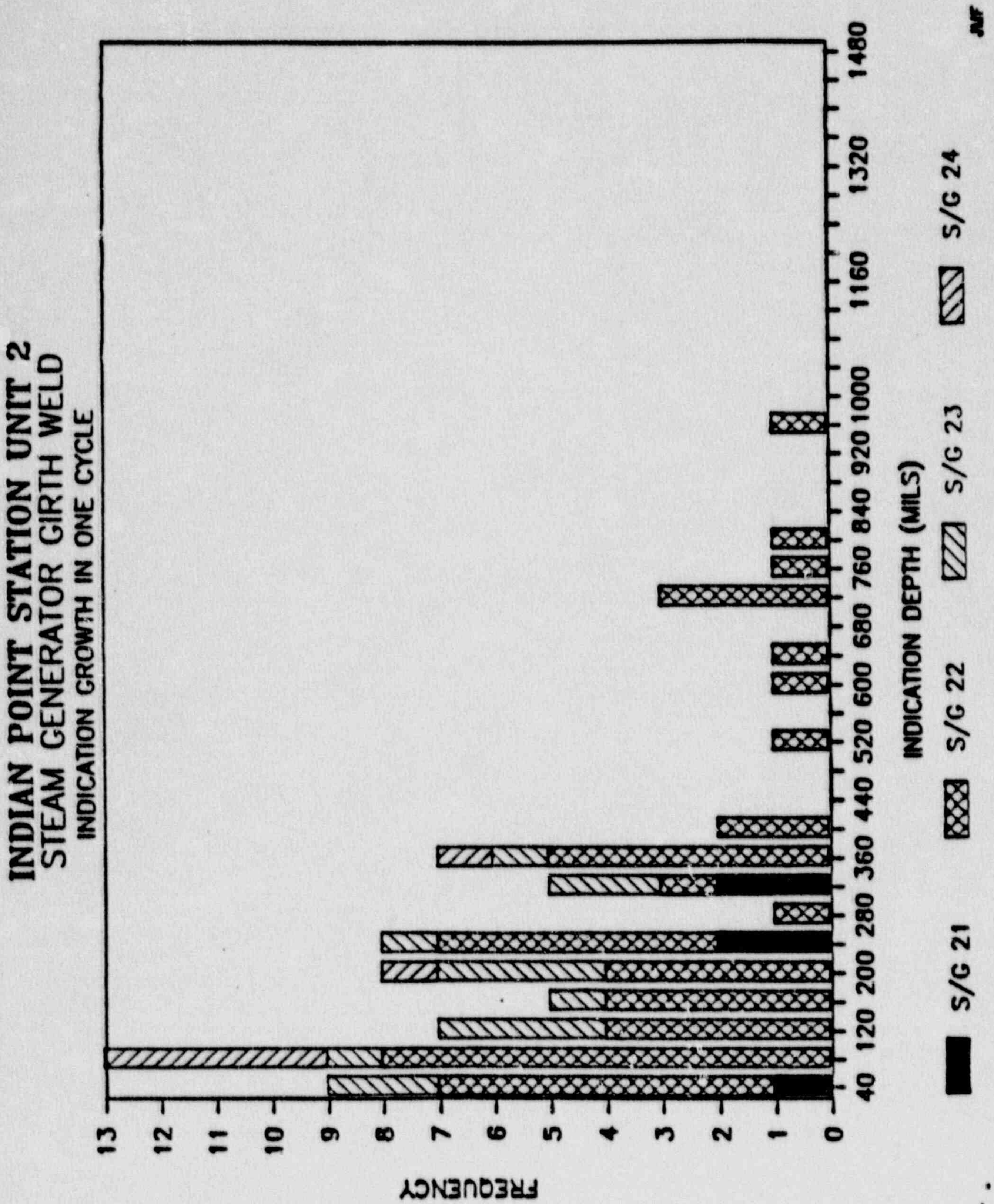


5/12/89

JMF

Figure 2.3-2

Figure 2.3-3


INDIAN POINT STATION UNIT 2
STEAM GENERATOR GIRTH WELD
INDICATION GROWTH IN ONE CYCLE
FREQUENCY
0 1 2 3 4 5 6 7 8 9 10 11 12 13
40 120 200 280 360 440 520 600 680 760 840 920 1000 1160 1320 1480
INDICATION DEPTH (MILS)
S/G 21
S/G 22
S/G 23
S/G 24

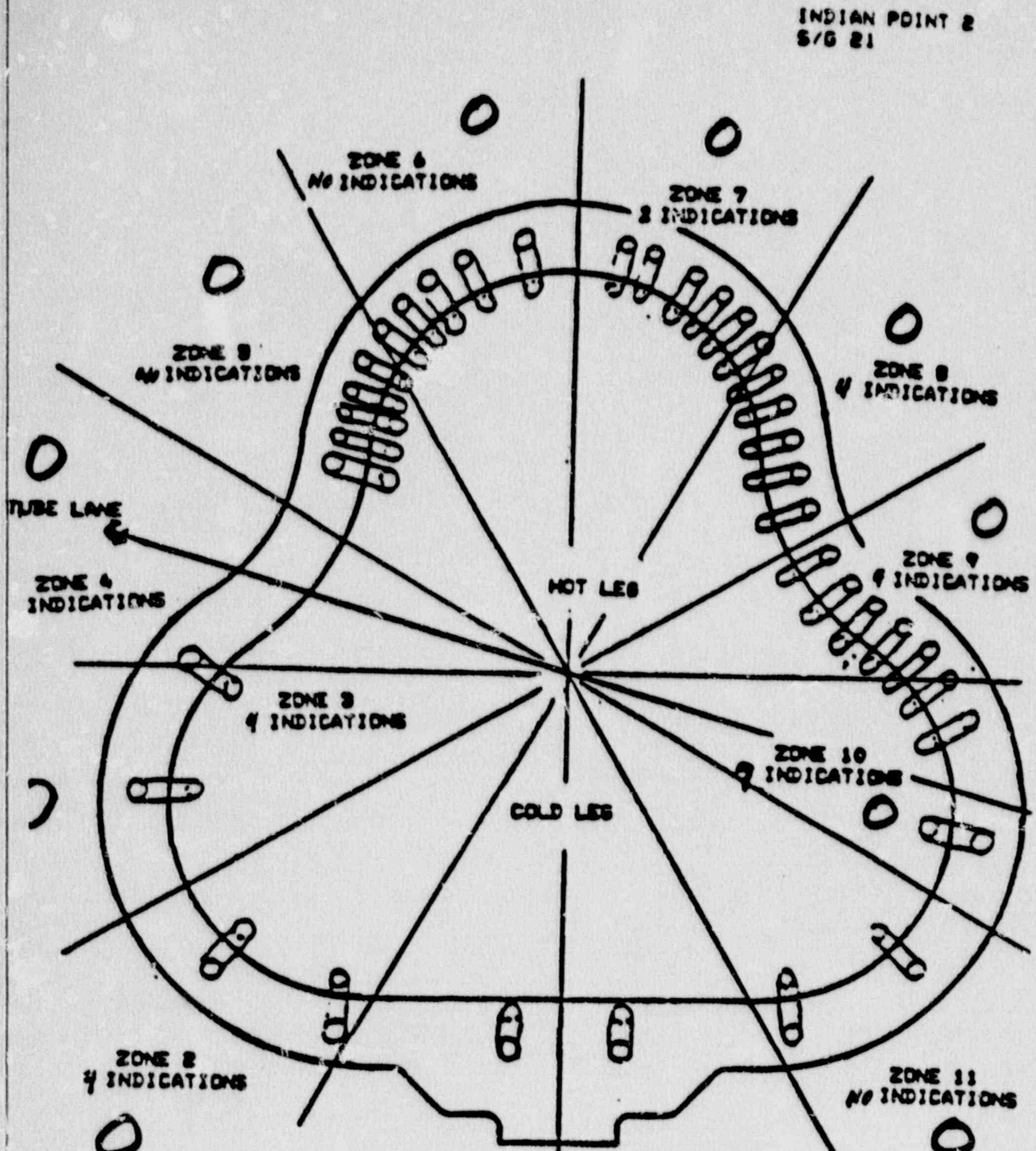

INDIAN POINT 2
S/G 21
ZONE 6
NO INDICATIONS
ZONE 7
2 INDICATIONS
ZONE 5
INDICATIONS
ZONE 8
4 INDICATIONS
TUBE LANE
ZONE 4
INDICATIONS
HOT LEG
ZONE 9
4 INDICATIONS
ZONE 3
4 INDICATIONS
ZONE 10
4 INDICATIONS
COLD LEG
ZONE 2
4 INDICATIONS
ZONE 11
NO INDICATIONS
ZONE 1
4 INDICATIONS
ZONE 12
4 INDICATIONS
2
3

Figure 2.3-4

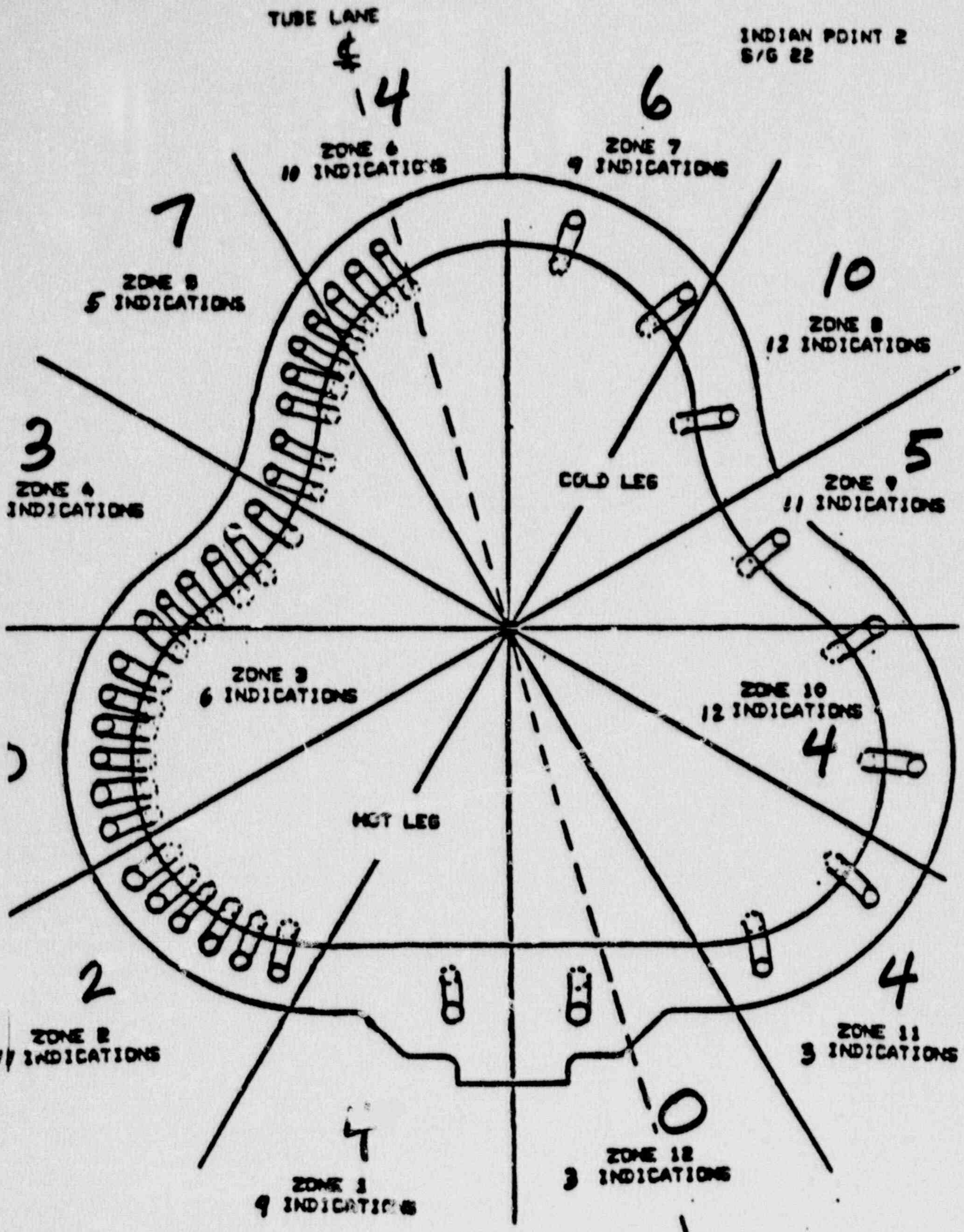
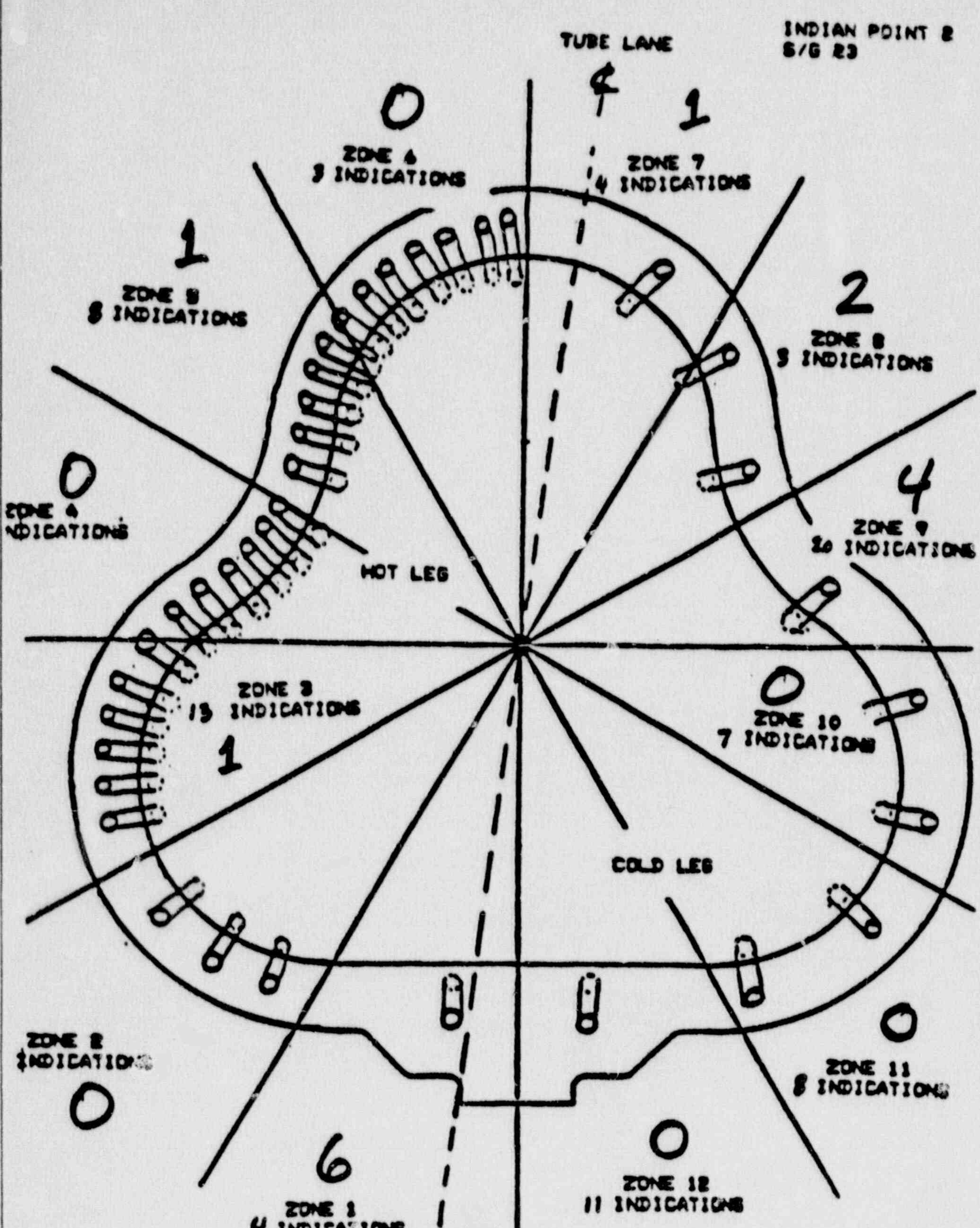

TUBE LANE
℄
INDIAN POINT 2
S/G 22
14
ZONE 6
10 INDICATIONS
6
ZONE 7
9 INDICATIONS
7
ZONE 5
5 INDICATIONS
10
ZONE 8
12 INDICATIONS
3
ZONE 4
INDICATIONS
COLD LEG
5
ZONE 9
11 INDICATIONS
ZONE 3
6 INDICATIONS
ZONE 10
12 INDICATIONS
4
HOT LEG
2
4
ZONE 2
11 INDICATIONS
ZONE 11
3 INDICATIONS
4
0
ZONE 12
3 INDICATIONS
ZONE 1
9 INDICATIONS

Figure 2.3-5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S/G 23
TUBE LANE
℄
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ZONE 7
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ZONE 5
8 INDICATIONS
2
ZONE 8
5 INDICATIONS
0
ZONE 4
INDICATIONS
4
ZONE 9
26 INDICATIONS
HOT LEG
ZONE 3
13 INDICATIONS
1
0
ZONE 10
7 INDICATIONS
COLD LEG
ZONE 2
INDICATIONS
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ZONE 11
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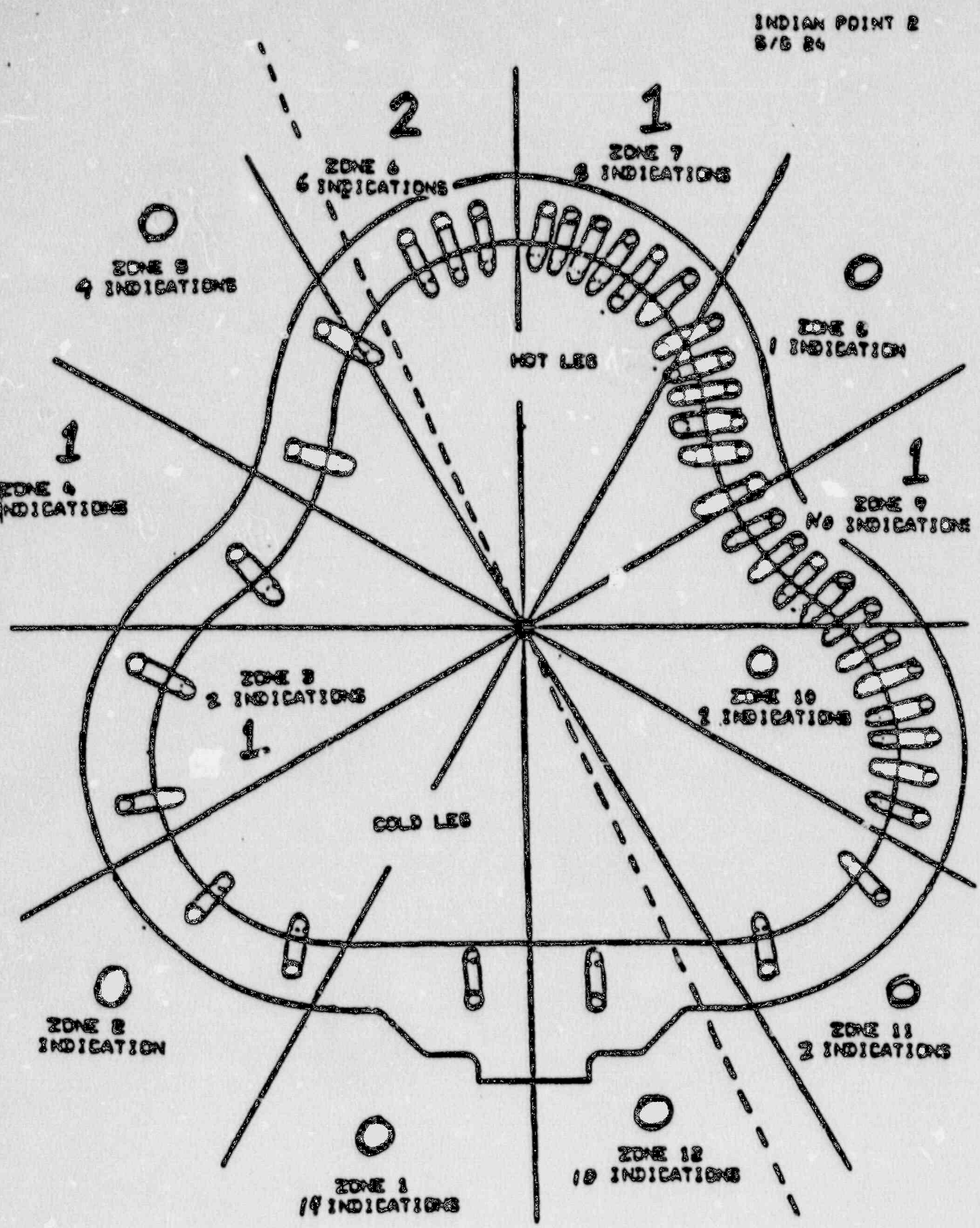
6
ZONE 1
4 INDICATIONS
0
ZONE 12
11 INDICATIONS

Figure 2.3-6


INDIAN POINT 2
S/G 24
2
1
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6 INDICATIONS
ZONE 7
3 INDICATIONS
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ZONE 8
1 INDICATION
HOT LEG
1
ZONE 4
INDICATIONS
1
ZONE 9
NO INDICATIONS
ZONE 3
2 INDICATIONS
1
0
ZONE 10
2 INDICATIONS
COLD LEG
0
ZONE 2
INDICATION
6
ZONE 11
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0
ZONE 12
10 INDICATIONS
0
ZONE 1
14 INDICATIONS

Figure 2.3-7

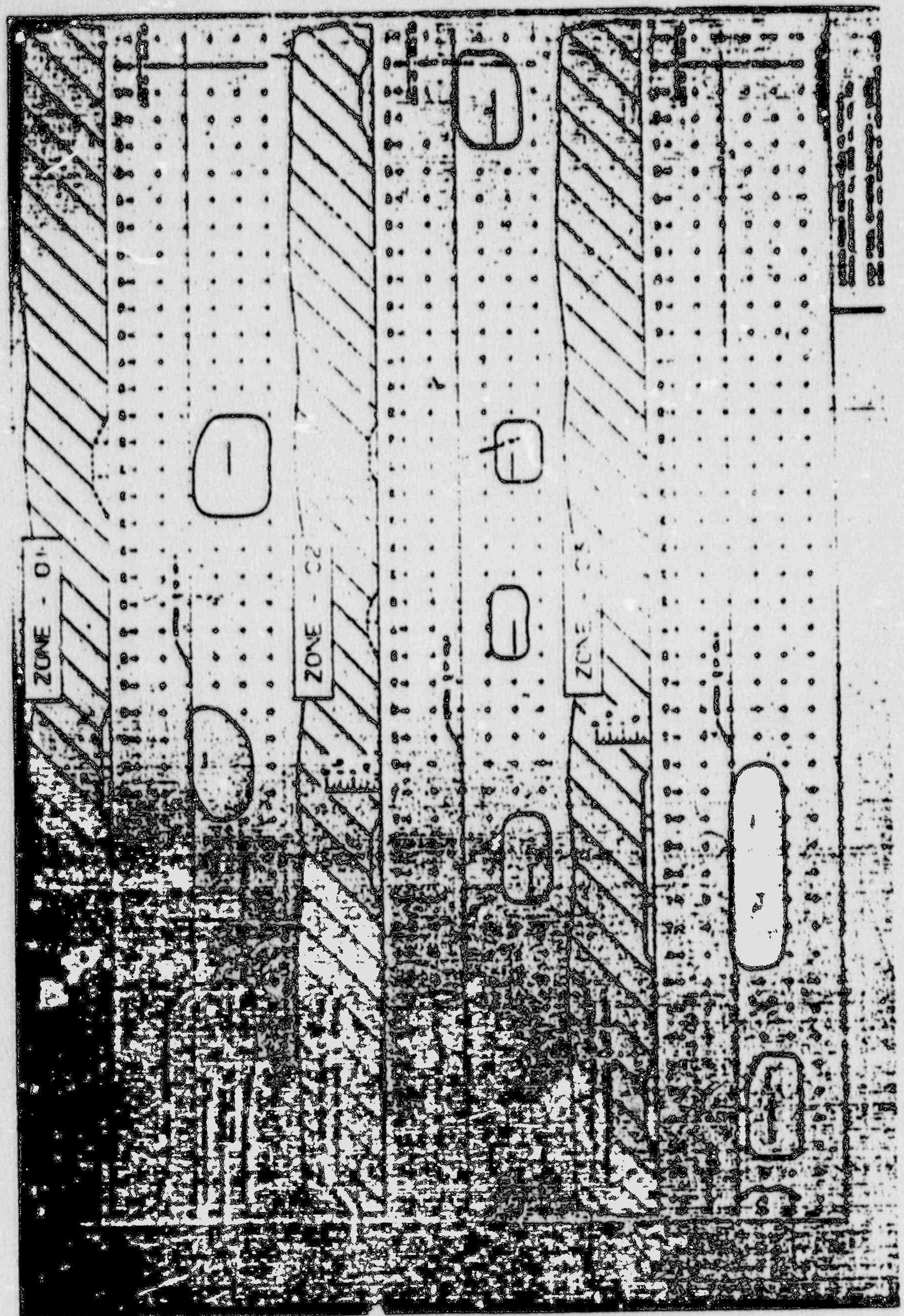
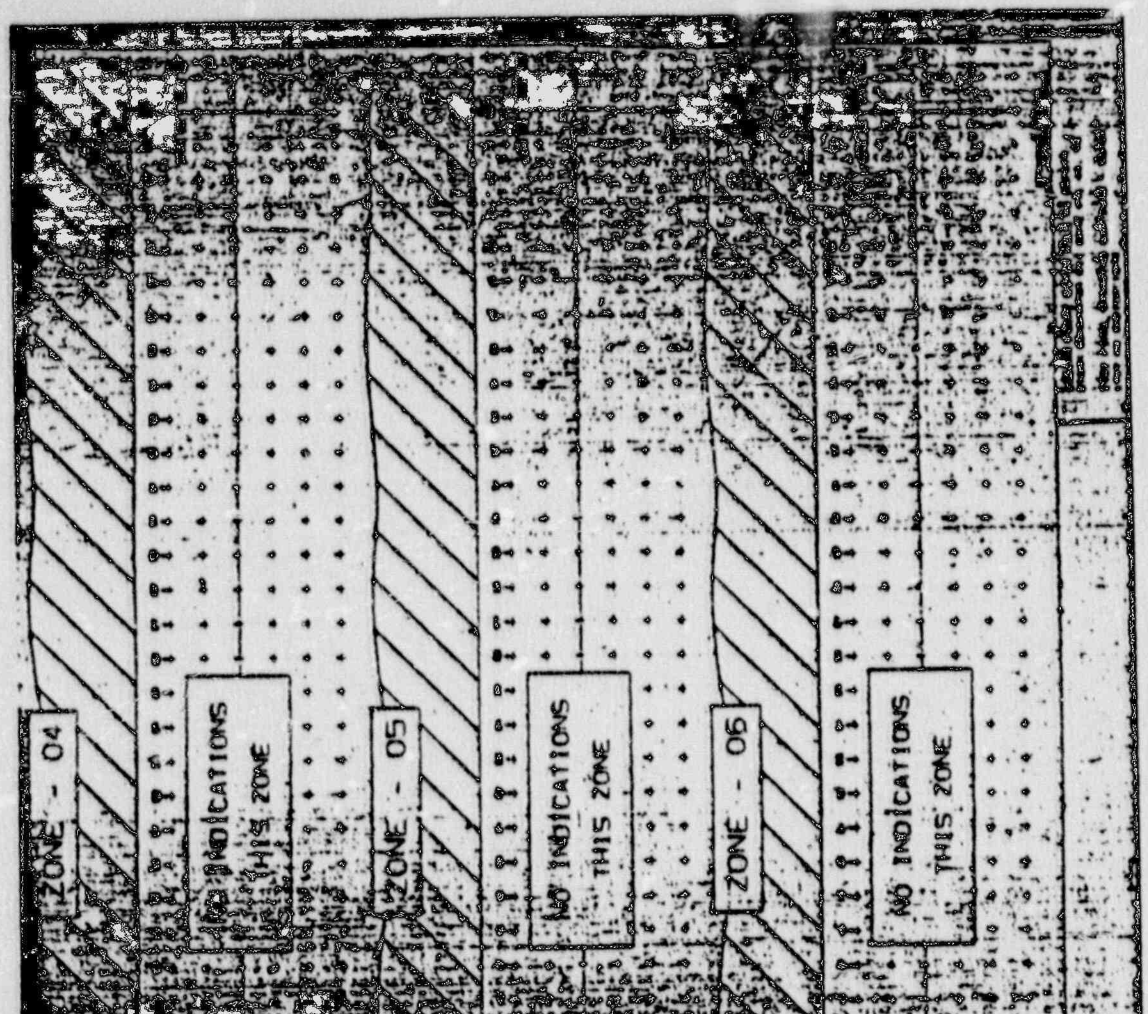


Figure 2.3-8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ZONE - 05
NO INDICATIONS THIS ZONE
ZONE - 06
NO INDICATIONS THIS ZONE

Figure 2.3-9

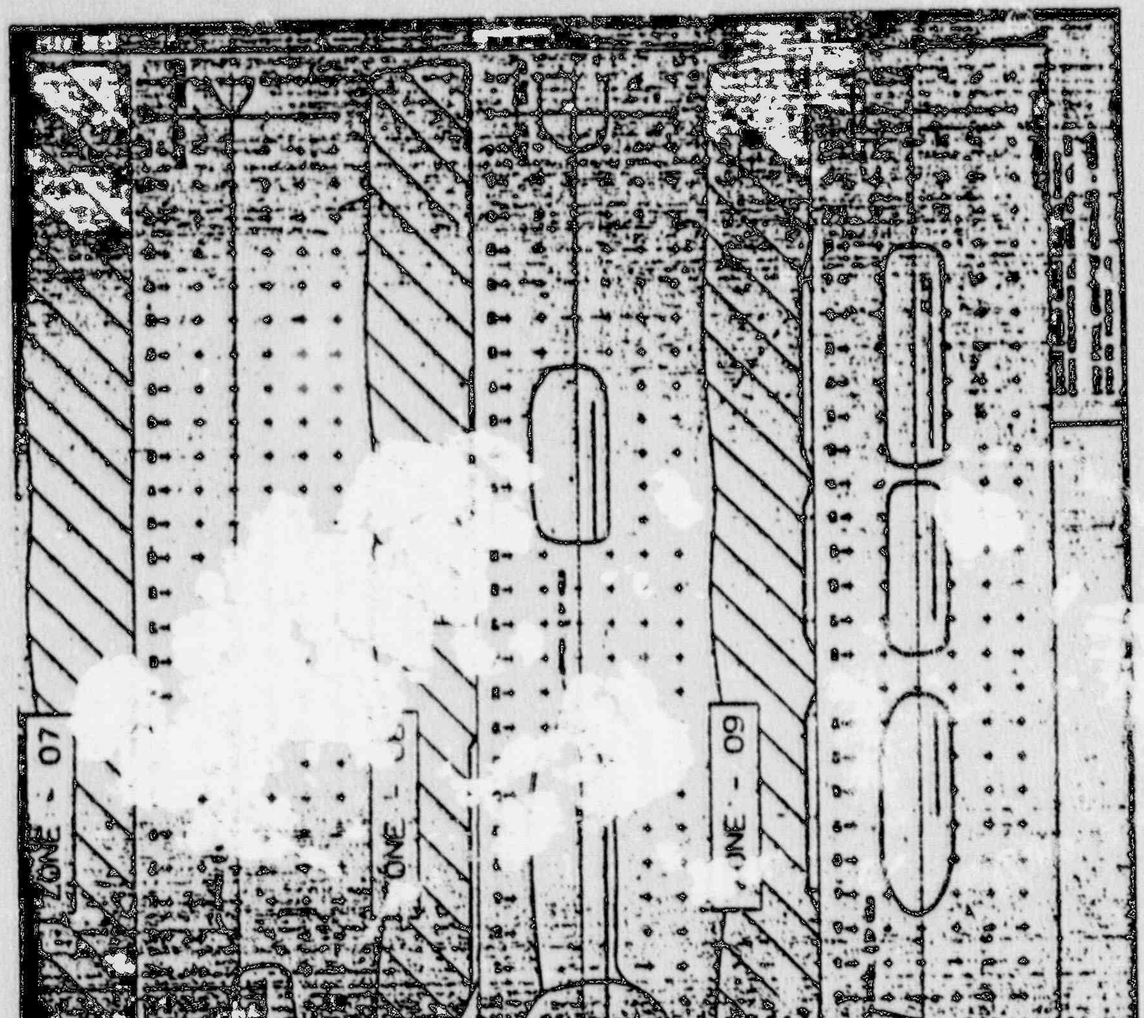


Figure 2.3-10

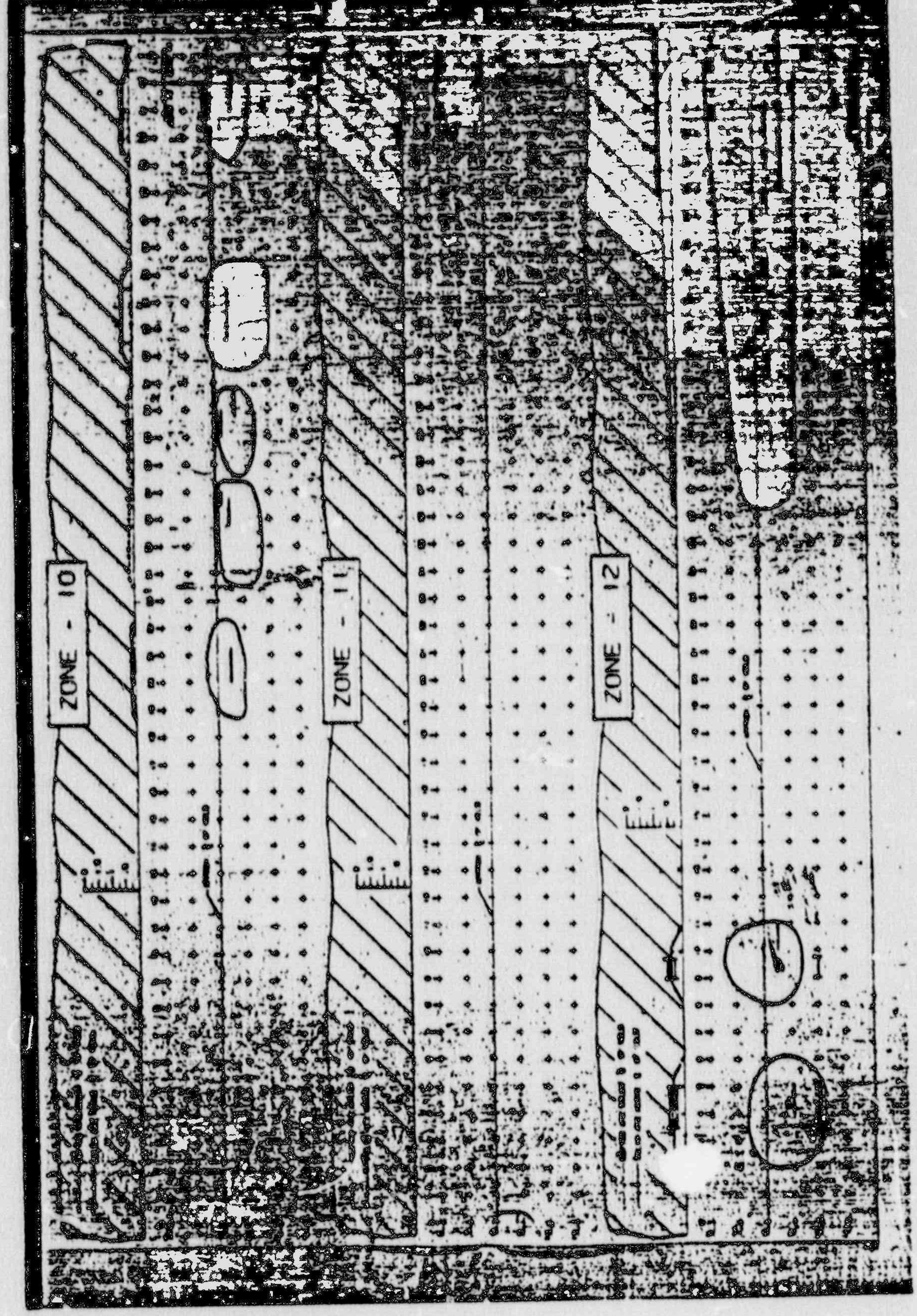


Figure 2.3-11

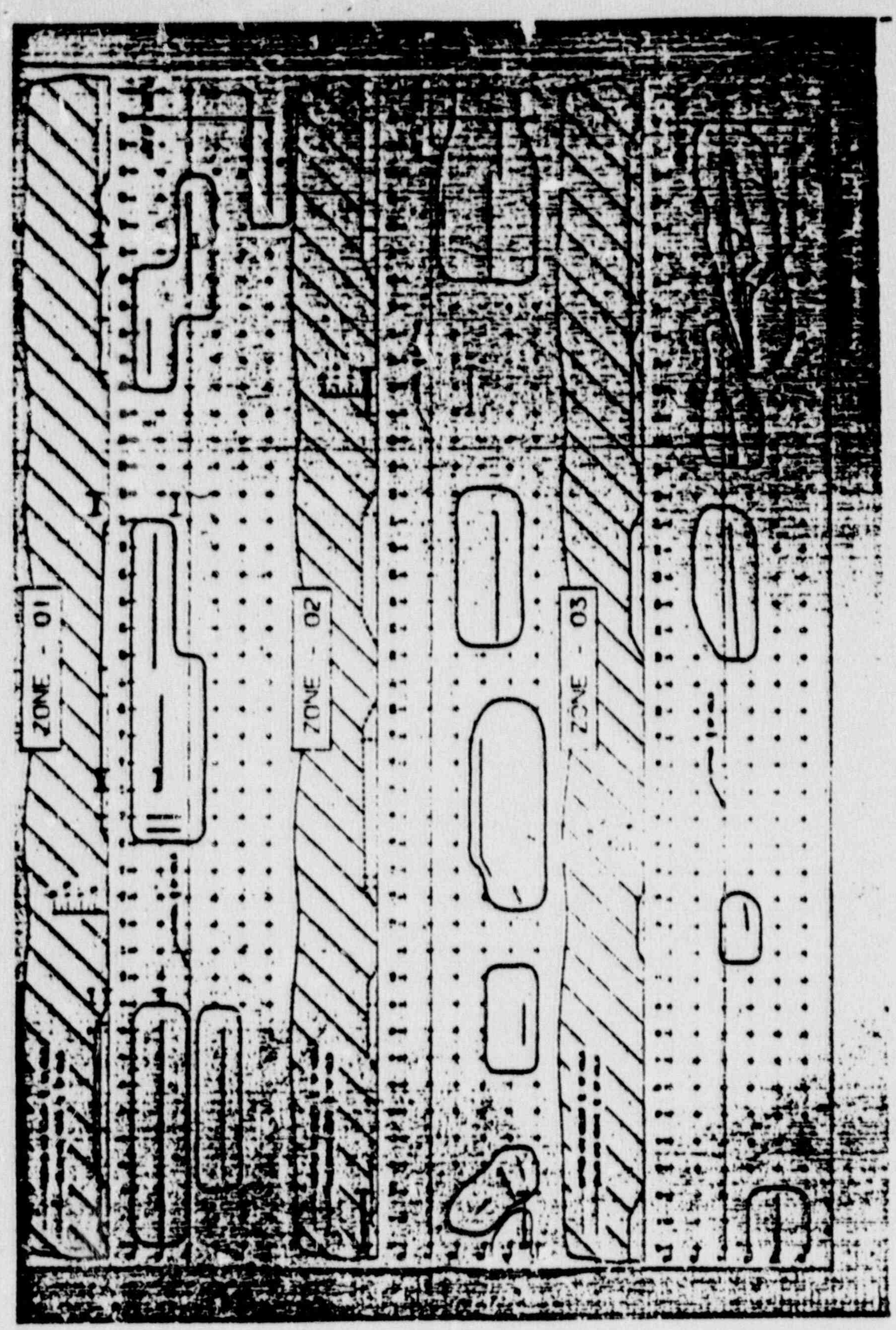


Figure 2.3-12

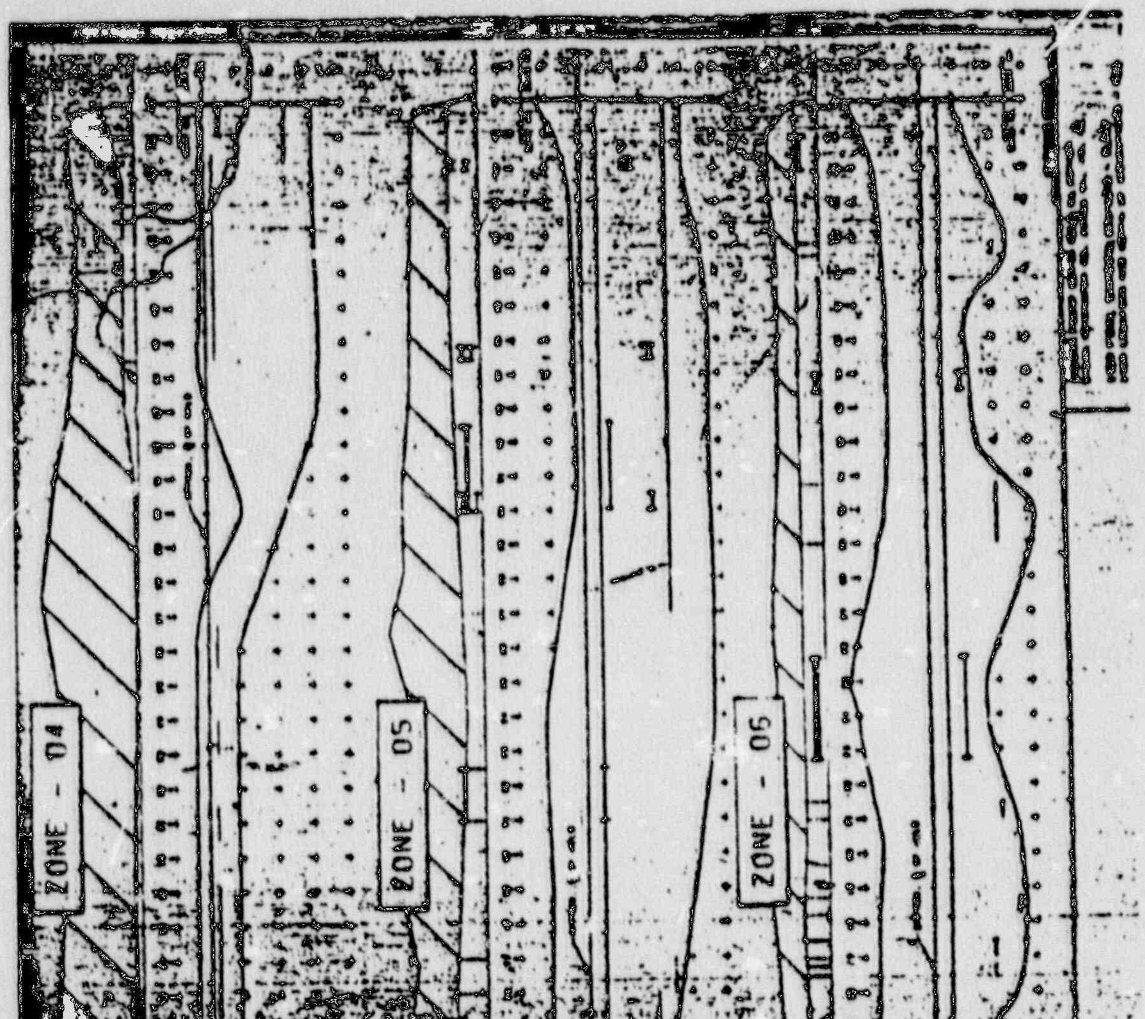


Figure 2.3-13

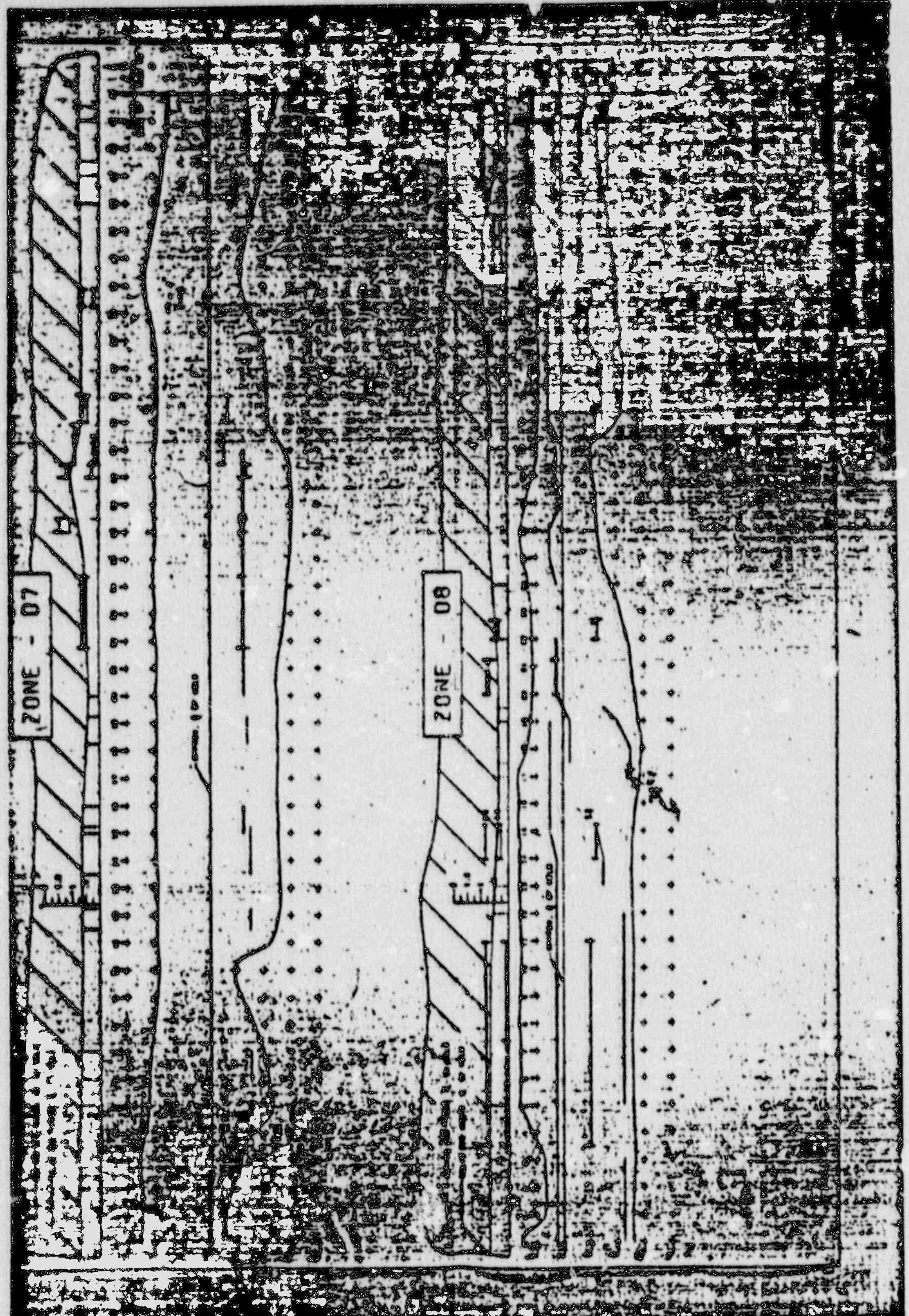


Figure 2.3-14

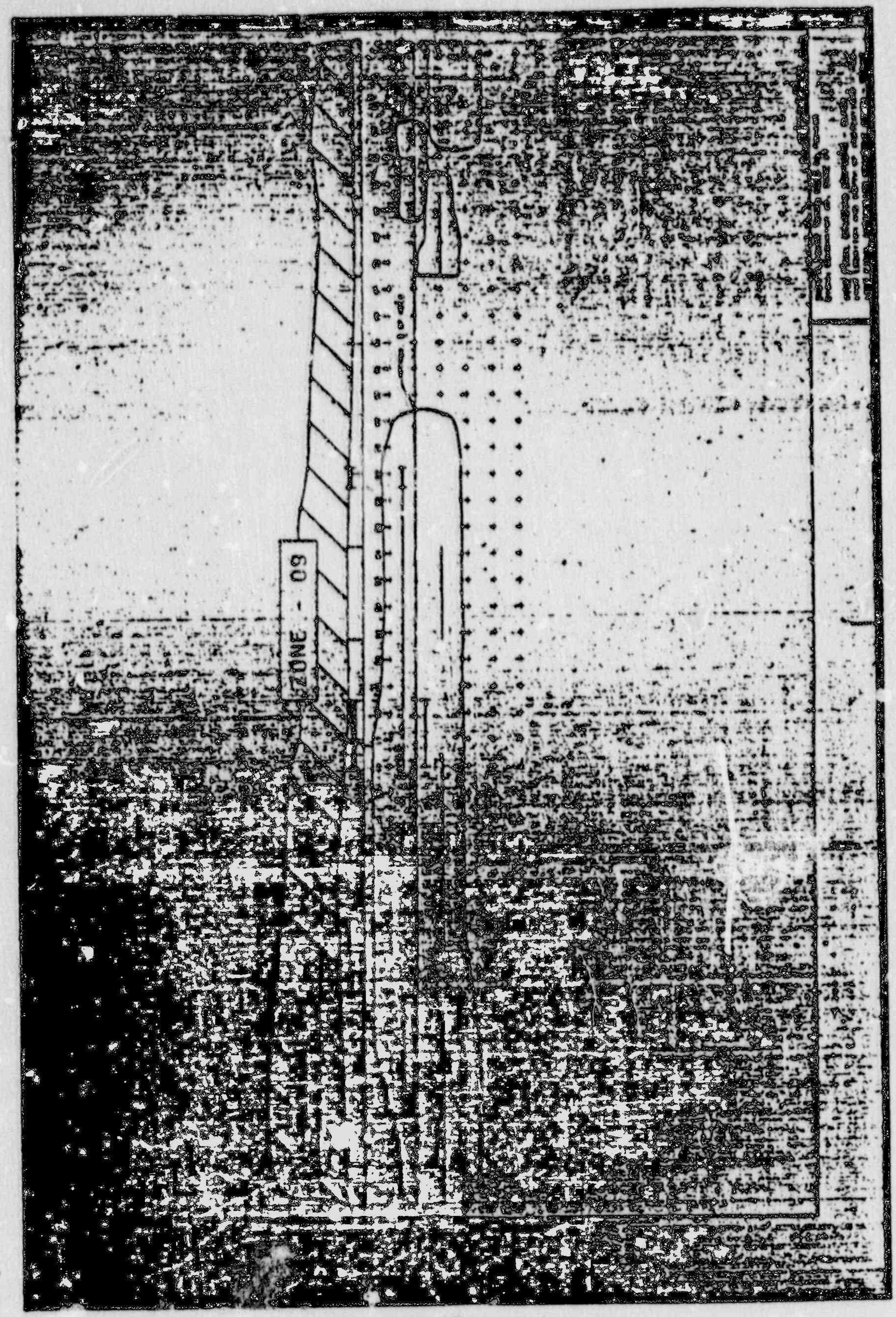


Figure 2.3-15

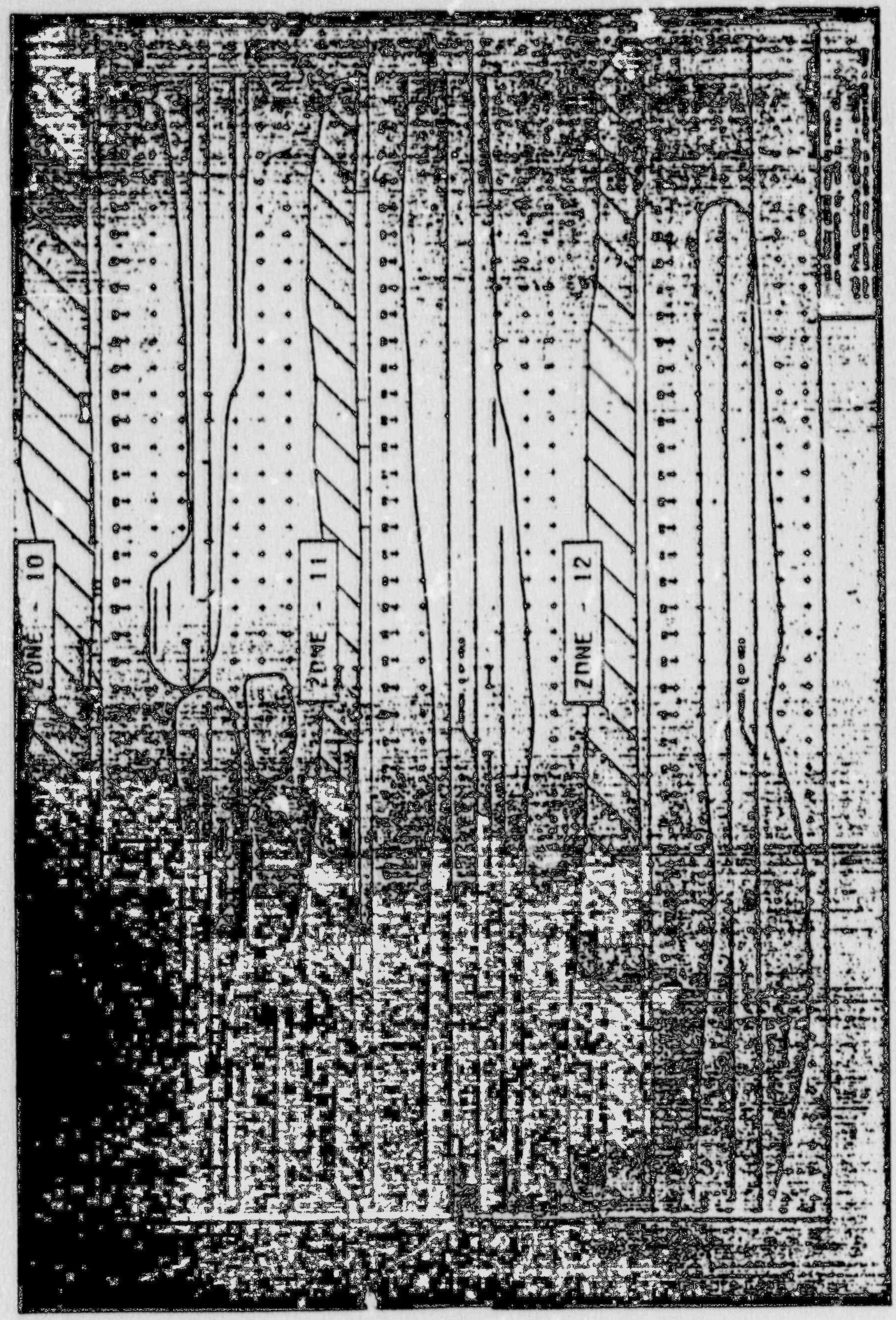


Figure 2.3-16

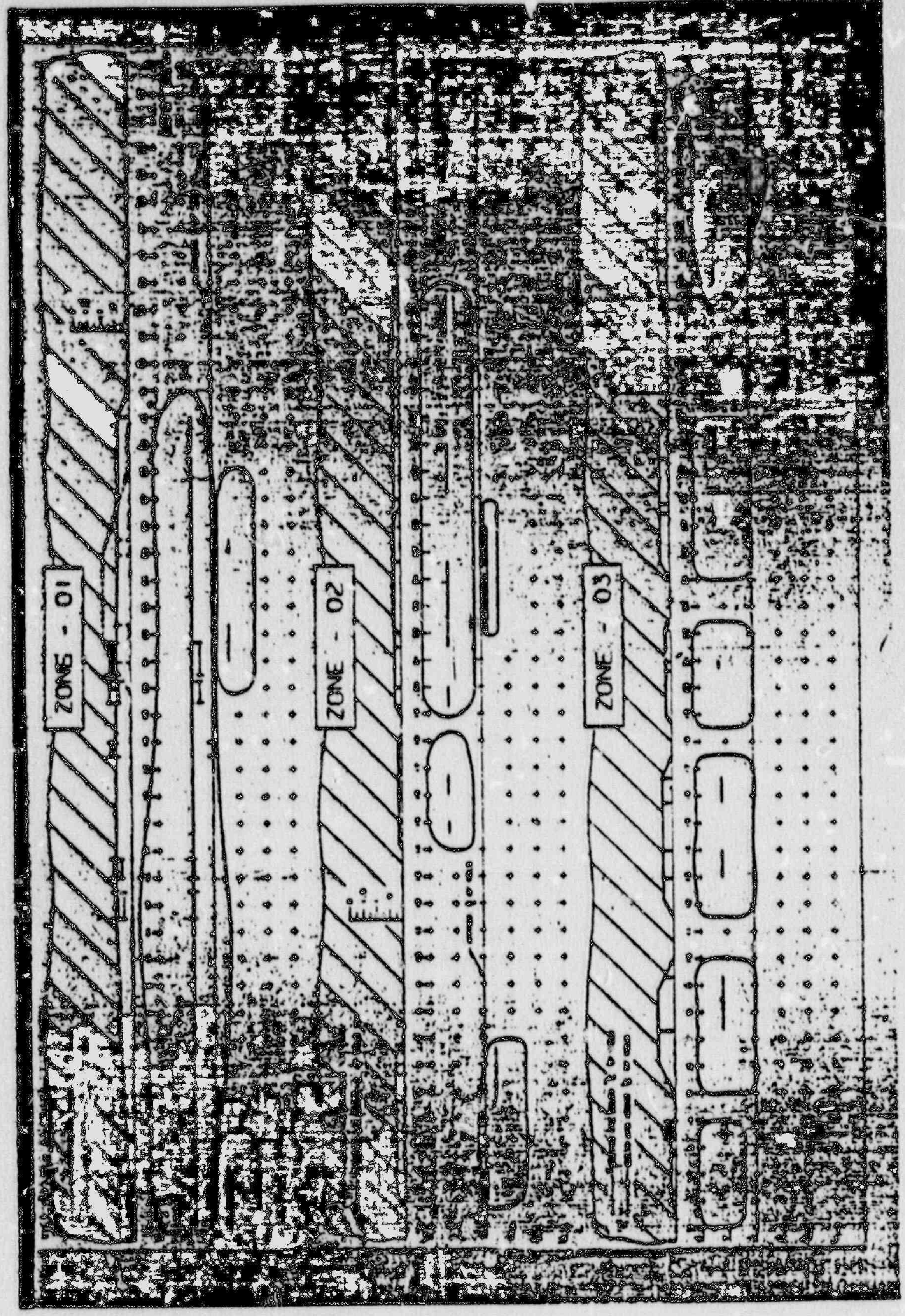


Figure 2.3-17

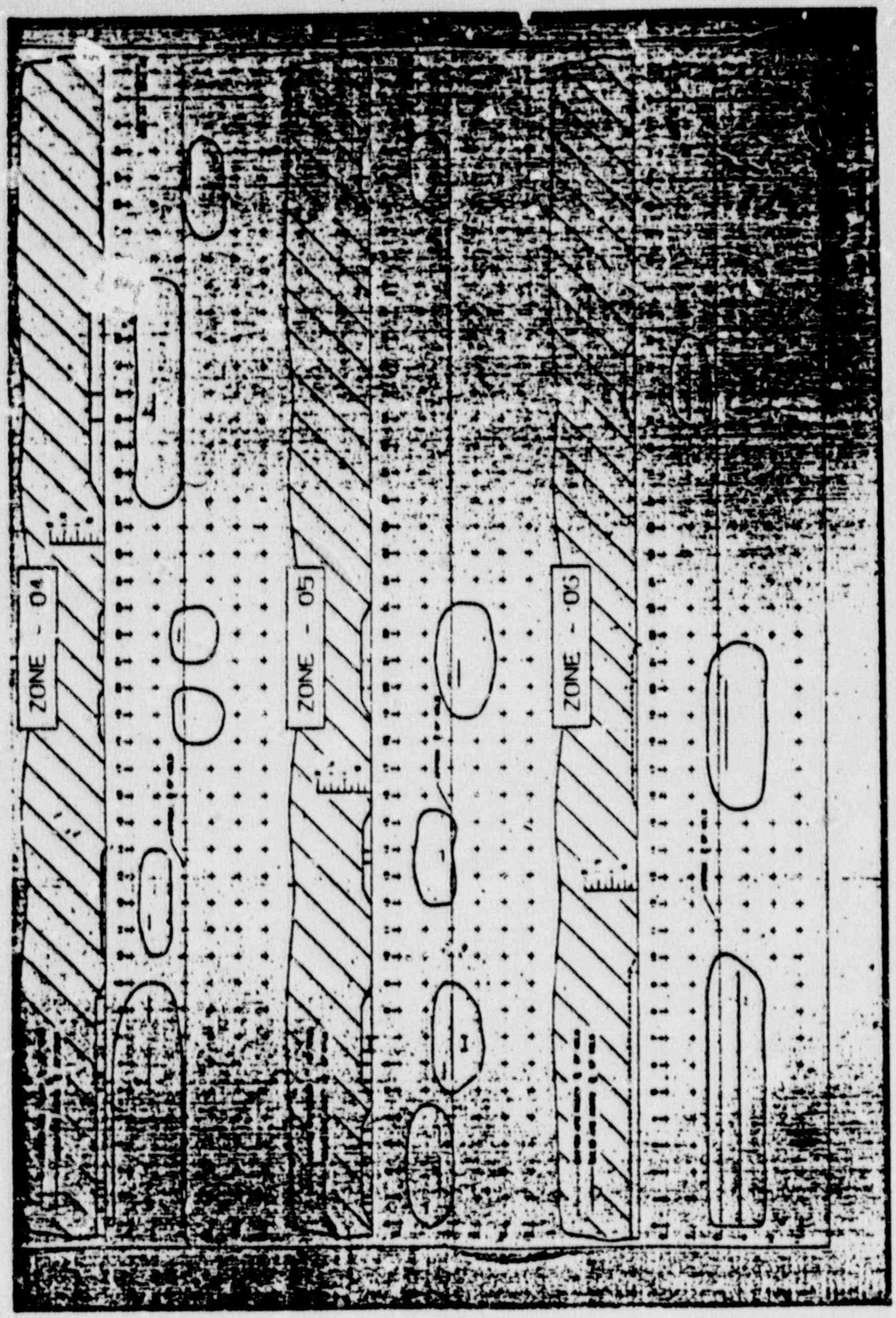


Figure 2.3-18

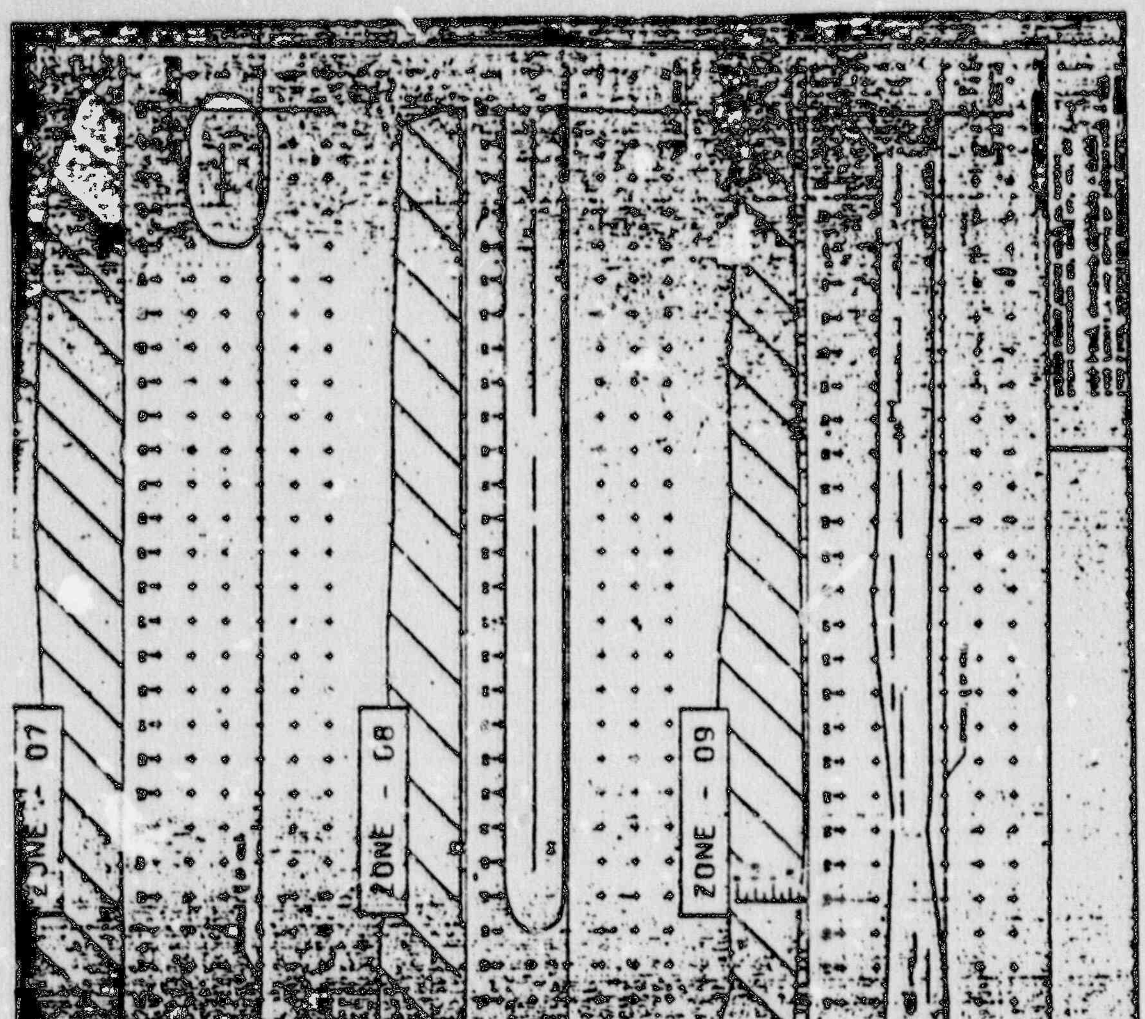


Figure 2.3-19

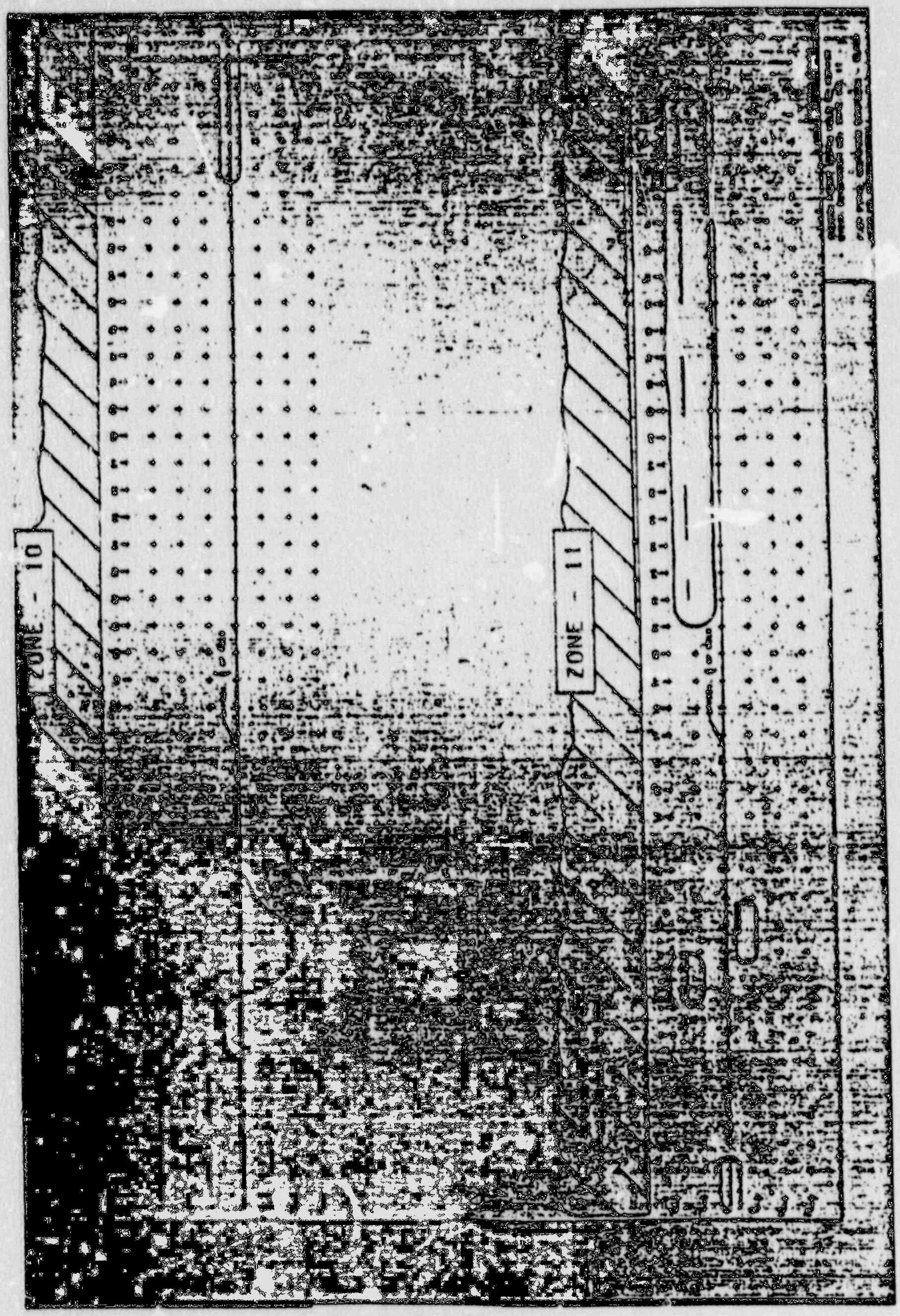


Figure 2.3-20

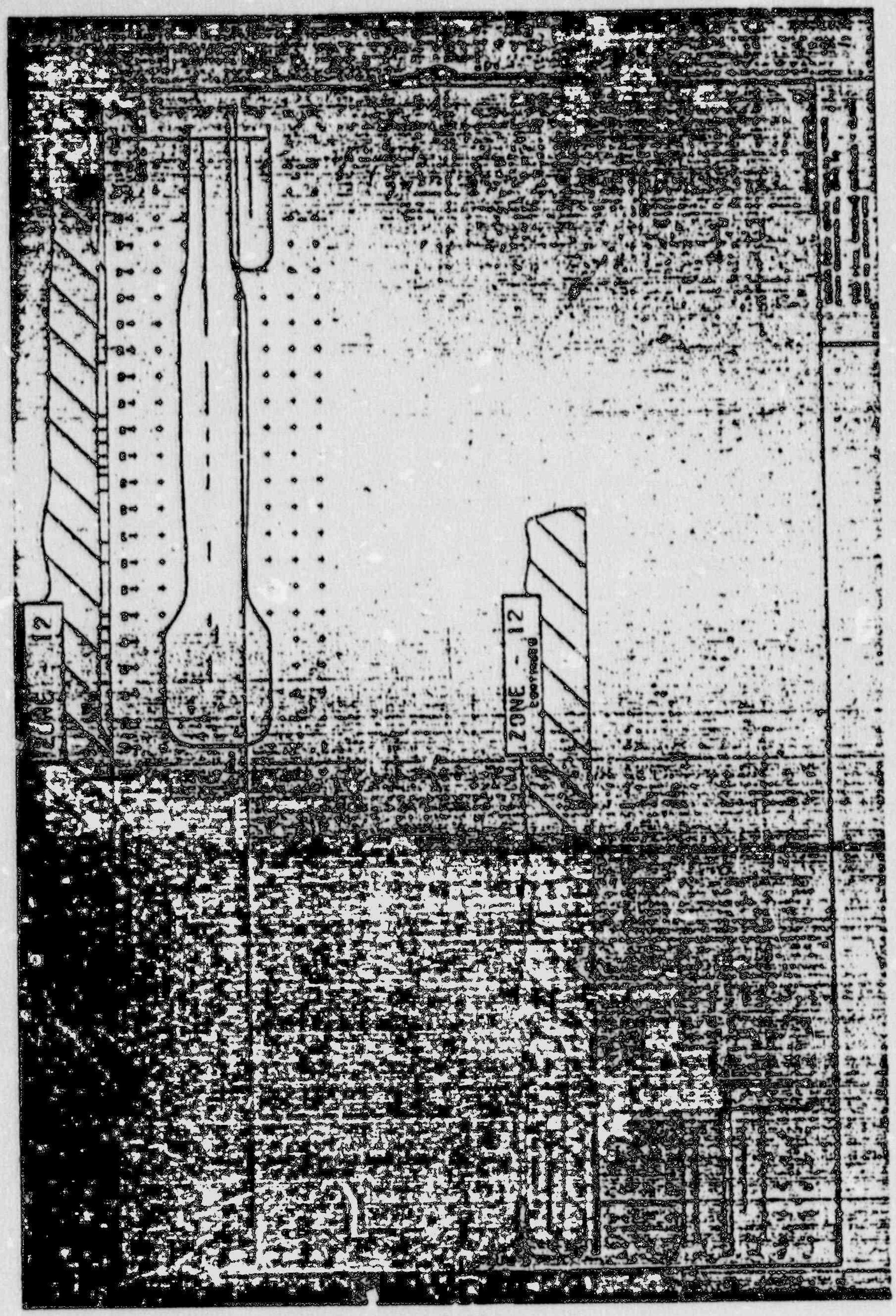


Figure 2.3-21

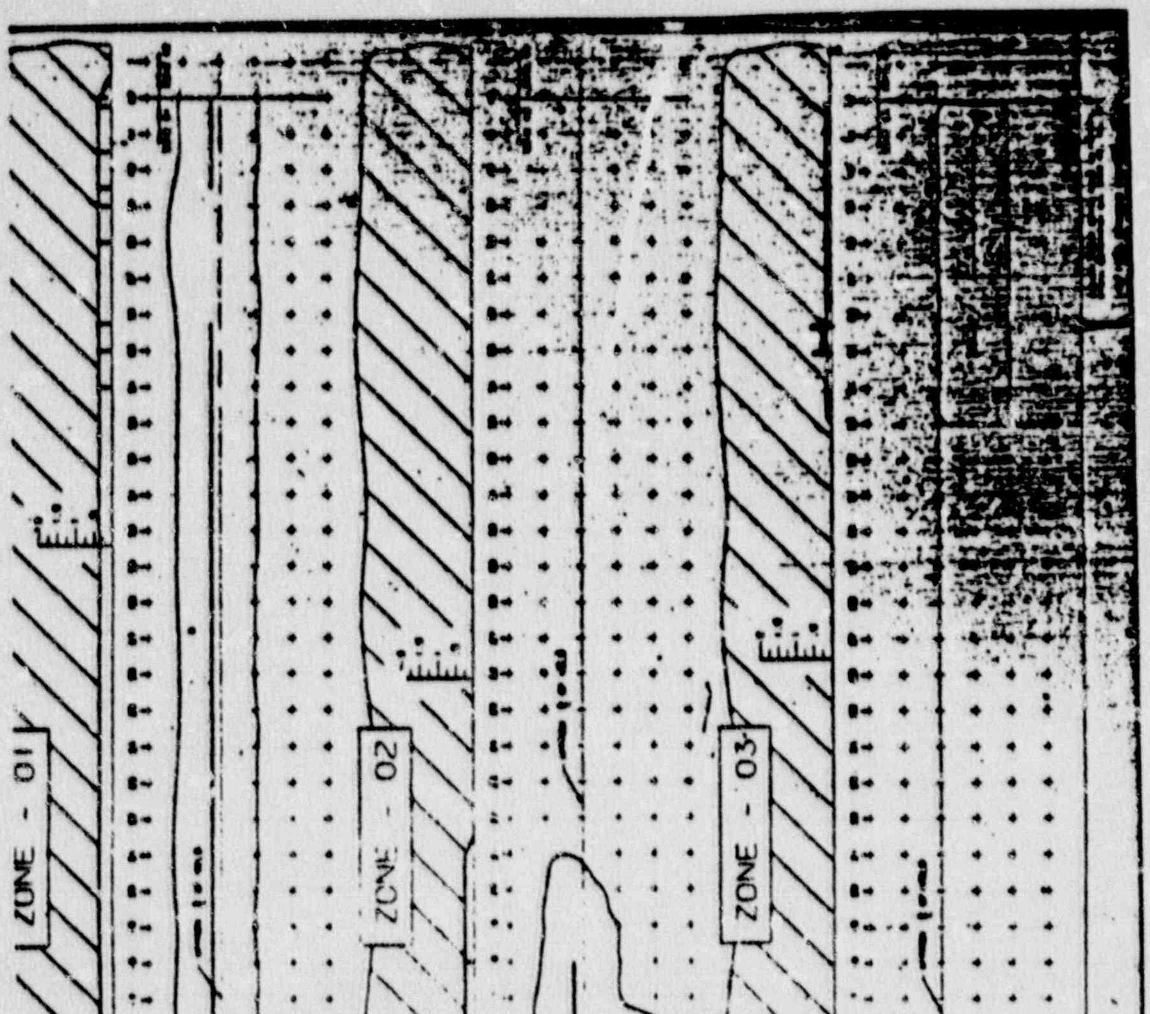


Figure 2.3-22

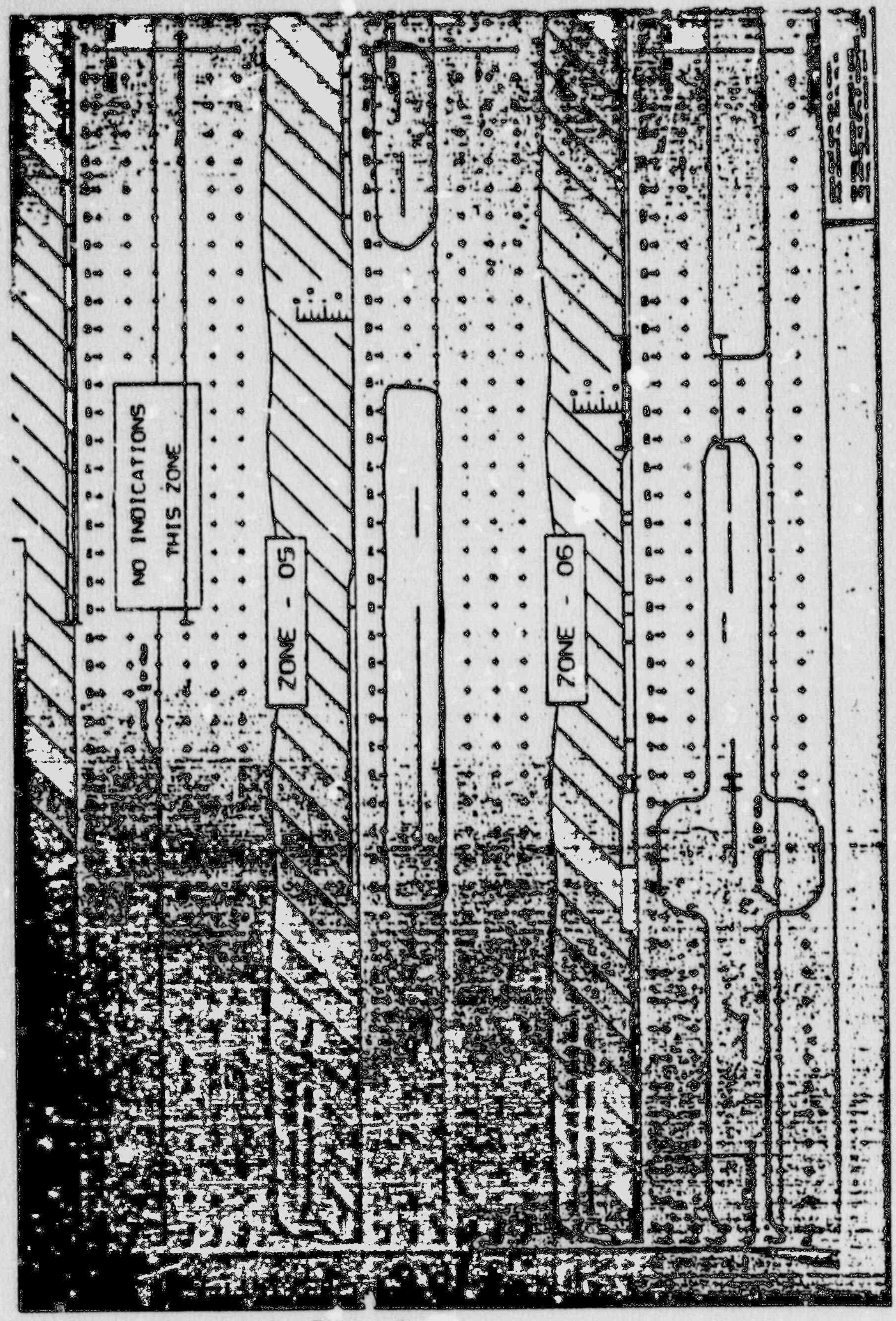


Figure 2.3-23

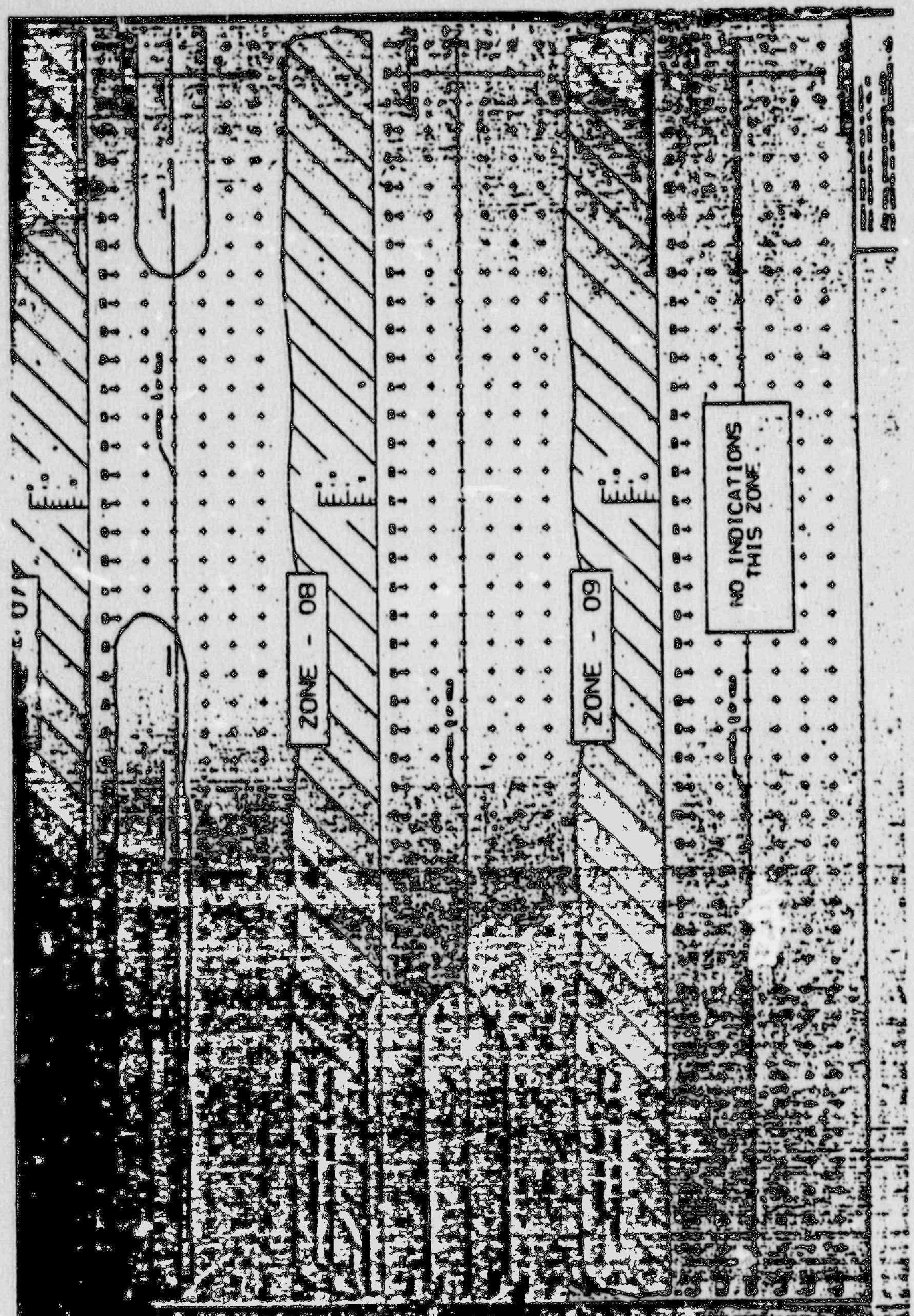


Figure 2.3-24

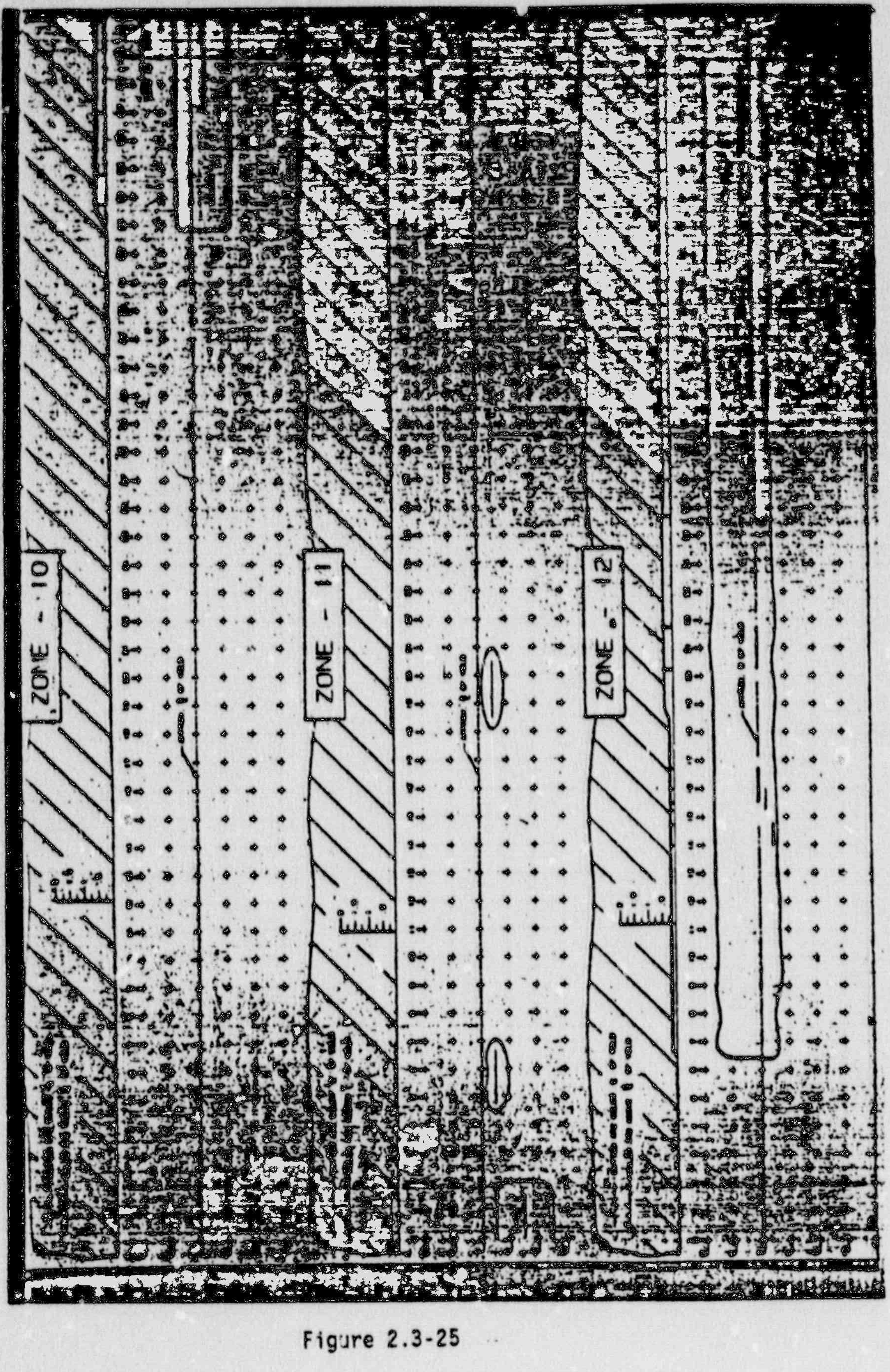


Figure 2.3-25

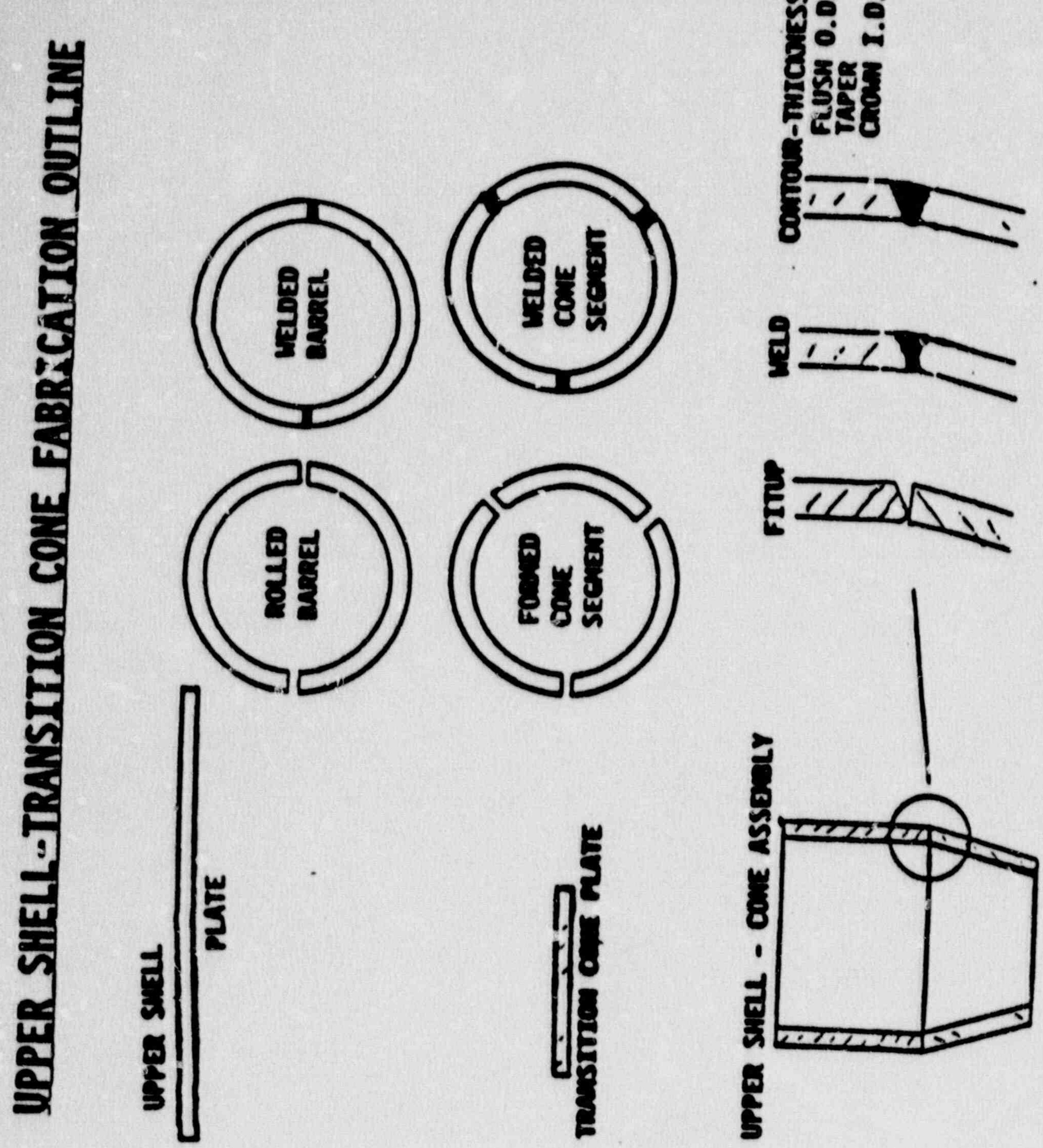

UPPER SHELL-TRANSITION CONE FABRICATION OUTLINE
UPPER SHELL
PLATE
ROLLED BARREL
WELDED BARREL
TRANSITION CONE PLATE
FORMED CONE SEGMENT
WELDED CONE SEGMENT
UPPER SHELL - CONE ASSEMBLY
FITUP
WELD
CONTOUR-THICKNESS
FLUSH O.D.
TAPER
CROWN I.D.

Figure 2.3-26

1989 OUTAGE
GIRTH WELD INDICATIONS

SG 21

ZONE NO.	IND NO.	END OF IND. FROM: ZONE LINE in.	END OF IND. FROM: HORIZ. REF + in.	IND LENGTH in.	DEPTH: STARTING mils	DEPTH: FINAL mils	DEPTH: GROWTH mils
1	1 #	3 3/4	8 5/8	3/4	270	570	300
	2	6	8 3/4	1/2	270	570	300
12	1 #	3 1/2	10	1 1/2	320	535	215
	2	9	10	3/4	300	512	212
	3 #	38	9	6	480	502	022

NOTES: ZONES 2 THRU 11 REPORTED NO INDICATIONS BY MT INSP.

\+ - HORIZONTAL LINE IS 24 1/2 in. BELOW CENTER LINE OF NOZZLE

\# - NEW INDICATION IS WITH IN 1/4" OF OLD INDICATION

5/15/89

Table 2.3-1

1989 OUTAGE
GIRTH WELD INDICATIONS

page 1

SG 22

ZONE NO.	IND NO.	END OF IND. FROM: ZONE LINE in.	END OF IND. FROM: HORIZ. REF * in.	IND LENGTH in.	DEPTH: STARTING mils	DEPTH: FINAL mils	DEPTH: GROWTH mils
1	1	9	6	1/2	052	629	577
	2	17	5 7/8	3/4	110	333	223
	3	27 1/4	6 1/2	3/4	392	461	069
	4	37 1/4	7 1/4	3/8	242	370	128
2	1	0	10 1/2	2	470	536	066
	2	31	8 1/2	1 3/4	263	324	061
4	1	5 1/2	8 1/4	1/2	085	316	231
	2	5 1/2	8 3/4	1/2	085	435	350
	3 #	9 1/4	7 1/2	1/2	170	514	339 ##
5	1	4 1/2	8	1/2	071	250	179
	2	6 1/2	8	1/2	090	437	347
	3	21	7 1/2	1 1/2	562	564	002
	4	30	9	1/2	171	539	368
	5	30	7 3/4	2 1/2	391	411	020
	6	34 1/2	9	3/8	265	544	279
	7	40	8 1/2	1/4	344	776	382
6	1 #	8 1/2	7 1/2	1	471	536	065
	2	22 3/4	8	3	290	334	044
	3	33 1/2	8	1/2	055	157	102
	4 #	40	7	1	566	580	014

5/15/89

Table 2.3-1 (Cont.)

1989 OUTAGE
GIRTH WELD INDICATIONS

GG 22

ZONE NO.	IND NO.	END OF IND. FROM: ZONE LINE in.	END OF IND. FROM: HORIZ. REF + in.	IND LENGTH in.	DEPTH: STARTING mils	DEPTH: FINAL mils	DEPTH: GROWTH mils
7	1 #	21 3/4	8 1/4	2 5/8	431	593	162
	2 #	26	8 1/4	1/2	1250	1420	170
	3	28	8 3/8	1/2	23	1179	949
	4	28 1/2	7 1/2	1	130	817	687
	5	30	7 5/8	1	420	549	129
	6	34 1/4	6	5/8	195	541	346
8	1	3 1/2	8	7 1/2	086	884	798
	2 #	14	8 1/4	1 1/4	255	857	602
	3	15 1/2	8	1/4	324	806	482
	4	20	6 3/4	1 1/4	665	780	105
	5	22	8 1/4	3/4	365	392	027
	6 #	29 1/2	8 1/4	1	573	682	109
	7	32 1/2	7	3/4	560	690	130
	8 #	35 1/2	7 3/4	2	220	452	232
	9	38 1/2	8 3/4	3 1/4	810	859	049
	10	43	7 3/4	1 3/4	625	1379	754

5/15/89

Table 2.3-1 (Cont.)

1989 OUTAGE
GIRTH WELD INDICATIONS

BS 22

page 3

ZONE NO.	IND NO.	END OF IND. FROM: ZONE LINE in.	END OF IND. FROM: HORIZ. REF + in.	IND LENGTH in.	DEPTH: STARTING mils	DEPTH: FINAL mils	DEPTH: GROWTH mils
9	1 #	4 1/2	8 1/4	3/4	125	258	133
	2	7 1/2	7	3/4	095	411	316
	3 #	9	8	1 1/4	525	582	057
	4	16	7 3/8	2 1/2	295	415	120
	5 #	26 1/2	6 1/2	3/4	415	443	028
10	1	19	6 1/4	1 3/4	365	702	337
	2	16	7 3/4	1/4	375	565	190
	3 #	24 1/2	7	3	350	356	006
	4 #	29	7	1	473	713	240
11	1	8 1/2	7	7	483	718	235
	2	12	7 1/2	4 1/2	688	740	052
	3	15	7	2	520	1236	716
	4	19	7 1/2	3/4	460	1160	700

NOTES: NO INDICATIONS - ZONE 3 & 12

+ HORIZONTAL REFERENCE LINE IS 26 in. BELOW CENTER LINE OF NOZZLE

- NEW INDICATION IS WITHIN 1/4 in. OF OLD INDICATION

- BOAT SAMPLE

5/15/89

Table 2.3-1 (Cont.)

SG 23

ZONE NO.	IND NO.	END OF IND. FROM ZONE LINE in.	END OF IND. FROM HORIZ. REF + in.	IND LENGTH in.	DEPTH STARTING mils	DEPTH FINAL mils	DEPTH GROWTH mils
1	1 #	11 1/2	7 1/4	1	339	538	199
	2 #	13	7 1/4	3/4	370	656	286
	3	17 1/2	8	1/2	553	735	186
	4 #	19 1/2	7 1/2	3/4	481	763	282
	5 #	20 1/2	7 1/2	1 1/4	525	752	227
	6	31 1/2	7 1/8	1/2	N/A	525	N/A ##
3	1 #	3 1/2	6 7/8	1/2	050	200	150
5	1 #	6 1/2	8 1/2	1/2	0	95	095
7	1	11 1/2	7	1/2	90	110	020
8	1	2 1/2	6 1/4	3/4	30	356	326
	2	20 1/4	7 1/2	1/4	125	320	195
9	1 #	4 1/4	7 1/2	3/4	748	788	040
	2 #	16	7	1/4	75	149	074
	3 #	32 1/2	6 3/4	1/4	140	237	097
	4 #	33	6 1/2	1/2	140	237	097

NOTES: NO INDICATIONS - ZONES 2,4,6,10,11 & 12

\+ - HORIZONTAL REFERENCE LINE IS 26 in. BELOW CENTER LINE OF NOZZLE

\# - NEW INDICATION IS WITH IN 1/4" OF OLD INDICATION

\## - FOUND DURING CONTOURING

5/15/89

Table 2.3-1 (Cont.)

1989 OUTAGE
GIRTH WELD INDICATIONS

SG 24

ZONE NO.	IND NO.	END OF IND. FROM: ZONE LINE in.	END OF IND. FROM: HORIZ. REF + in.	IND LENGTH in.	DEPTH: STARTING mils	DEPTH: FINAL mils	DEPTH: GROWTH mils
3	1	35	8	3/4	218	284	066
4	1	21 1/2	8	21	- 084 #	255	339
					0	283 ##	
6	1 $	15 1/2	5 1/2	1/2	151	328	177
	2 $	27 3/4	5 1/4	4	097	211	114
7	1 $	1	6	1	195	256	061
9	1	35	7	7	087	158	071

NOTES: NO INDICATIONS - ZONES 1,2,5,8,10, & 12

+ - HORIZONTAL REFERENCE LINE IS ___ " BELOW CENTER LINE OF NOZZLE

- NEGATIVE BECAUSE IND. ON CONE SURFACE

$ - NEW INDICATION IS WITHIN 1/4 in. OF OLD INDICATION

- BOAT SAMPLE 5/15/89

Table 2.3-1 (Cont.)

INDIAN POINT UNIT 2

SUMMARY OF NUMBER OF INDICATIONS PER ZONE
AND MAX OVERALL DEPTH, STEAM GENERATOR 21

	1989		1987	
ZONE	# OF IND.	MAX. DEPTH	# OF IND.	MAX. DEPTH
1	2	.57	4	.56
2	NONE	N/A	4	.40
3	NONE	N/A	4	.37
4	NONE	N/A	NONE	N/A
5	NONE	N/A	NONE	N/A
6	NONE	N/A	NONE	N/A
7	NONE	N/A	2	.28
8	NONE	N/A	4	.36
9	NONE	N/A	4	.32
10	NONE	N/A	7	.36
11	NONE	N/A	NONE	N/A
12	3	.54	9	.50
TOTALS	5		38	

Table 2.3-2

INDIAN POINT UNIT 2

SUMMARY OF NUMBER OF INDICATIONS PER ZONE
AND MAX OVERALL DEPTH, STEAM GENERATOR 22

	1989		1987	
ZONE	# OF IND.	MAX. DEPTH	# OF IND.	MAX. DEPTH
1	4	.63	9	.49
2	2	.54	11	.68
3	NONE	N/A	6	.56
4	3	.51	10	.88
5	7	.78	5	1.00
6	4	.58	10	.76
7	6	1.42	9	1.07
8	10	1.38	12	.89
9	5	.58	11	1.01
10	4	.71	12	.51
11	4	1.24	3	.85
12	NONE	N/A	3	.49
TOTALS	49		101	

Table 2.3-3

INDIAN POINT UNIT 2

SUMMARY OF NUMBER OF INDICATIONS PER ZONE
AND MAX OVERALL DEPTH, STEAM GENERATOR 23

	1989		1987	
ZONE	# OF IND.	MAX. DEPTH	# OF IND.	MAX. DEPTH
1	6	.76	4	1.01
2	NONE	N/A	11	.33
3	1	.20	13	.65
4	NONE	N/A	10	.49
5	1	.09	8	.38
6	NONE	N/A	3	.34
7	1	.11	4	.42
8	2	.36	3	.16
9	4	.79	20	.65
10	NONE	N/A	7	.58
11	NONE	N/A	8	.29
12	NONE	N/A	11	.57
TOTALS	15		102	

Table 2.3-4

INDIAN POINT UNIT 2

SUMMARY OF NUMBER OF INDICATIONS PER ZONE
AND MAX OVERALL DEPTH, STEAM GENERATOR 24

	1989		1987	
ZONE	# OF IND.	MAX. DEPTH	# OF IND.	MAX. DEPTH
1	NONE	N/A	14	.48
2	NONE	N/A	1	.27
3	1	.28	3	.13
4	1	.28	NONE	N/A
5	NONE	N/A	4	.42
6	2	.33	6	.57
7	1	.26	8	.36
8	NONE	N/A	1	.51
9	1	.16	NONE	N/A
10	NONE	N/A	2	.33
11	NONE	N/A	2	.07
12	NONE	N/A	10	.40
TOTALS	6		50	

Table 2.3-5

INDIAN POINT UNIT 2

FINAL MAX. DEPTH OF GRIND

(COMBINATION OF 1987 AND 1989 DATA)

	S/G 21		S/G 22		S/G 23		S/G 24	
ZONE	1989	1987	1989	1987	1989	1987	1989	1987
1	.57	.56	.63	.49	.76	1.01	.48	.48
2	.40	.40	.54	.68	.33	.33	.27	.27
3	.37	.37	.56	.56	.20	.65	.28	.13
4	N/A		.51	.88	.49	.49	.28	.00
5	N/A		.73	1.00	.09	.38	.42	.42
6	N/A		.58	.76	.34	.34	.33	.57
7	.28	.28	1.42	1.07	.11	.42	.26	.36
8	.36	.36	1.38	.89	.36	.16	.51	.51
9	.32	.32	.58	1.01	.79	.65	.16	.00
10	.36	.36	.71	.51	.58	.58	.33	.33
11	N/A		1.24	.85	.29	.29	.07	.07
12	.54	.50	.49	.49	.57	.57	.40	.40

Table 2.3-6

INDIAN POINT UNIT 2

AVERAGE DEPTH OF GRINDING

	S/G 21		S/G 22		S/G 23		S/G 24	
ZONE	1989	1987	1989	1987	1989	1987	1989	1987
1	.30	.49	.25	.31	.28	.80	N/A	.38
2	N/A	.38	.06	.46	N/A	.25	N/A	.25
3	N/A	.32	N/A	.45	.15	.31	.07	.12
4	N/A	N/A	.31	.30	N/A	.27	.35	N/A
5	N/A	N/A	.23	.85	.10	.31	N/A	.29
6	N/A	N/A	.06	.56	N/A	.24	.15	.37
7	N/A	.20	.41	.64	.02	.25	.06	.24
8	N/A	.21	.33	.58	.26	.15	N/A	.51
9	N/A	.27	.13	.66	.08	.26	.07	N/A
10	N/A	.19	.19	.41	N/A	.41	N/A	.30
11	N/A	N/A	.43	.63	N/A	.19	N/A	.04
12	.15	.29	N/A	.37	N/A	.41	N/A	.25
AVERAGE:	.21	.29	.26	.51	.19	.31	.17	.30

OVERALL AVERAGE (ALL 4 S/Gs) = .24

Table 2.3-7

GIRTH WELD INDICATION SUMMARY

	SG21	SG22	SG23	SG24
1987				
# OF INDICATIONS	38	101	102	50
MAX. DEPTH *	0.56"	1.07"	1.01"	0.57"
AVG. DEPTH	0.29"	0.49"	0.31"	0.29"
1989				
# OF INDICATIONS	5	49	15	7
MAX. DEPTH *	0.30"	0.95"	0.33"	0.34"
AVG. DEPTH	0.21"	0.26"	0.16"	0.14"

* DEPTH OF GRIND REQUIRED TO REMOVE INDICATION

Table 2.3-8

SUMMARY OF MT INDICATIONS
PER HOT LEG/COLD LEG DISTRIBUTION

	HOT LEG 1989	HOT LEG 1987	COLD LEG 1989	COLD LEG 1987
S/G 21	NONE	13	5	25
S/G 22	17	47	32	54
S/G 23	8	49	7	53
S/G 24	4	21	2	29

- NO APPARENT CORRELATION

Table 2.3-9

SUMMARY OF MT INDICATIONS PER ZONES

S/G		ZONES 12	1	2	3	4	5	6	7	8	9	10	11
21	(1987)	9	4	4	4	0	0	0	2	4	4	7	0
	(1989)	3	2	0	0	0	0	0	0	0	0	0	0
22	(1987)	3	9	11	6	10	5	10	9	12	11	12	3
	(1989)		4	2	0	3	7	4	6	10	5	4	4
23	(1987)	11	4	11	13	10	8	3	4	3	20	7	8
	(1989)	0	6	0	1	0	1	0	1	2	4	0	0
24	(1987)	10	14	1	2	0	4	6	8	1	0	2	2
	(1989)	0	0	0	1	1	0	2	1	0	1	0	0
AL:													
	(1987)	33	31	27	25	20	17	19	23	20	35	28	13
	(1989)	3	12	2	2	4	8	6	8	12	10	4	4
		FWN		RISER		THROUGH		RISER		THROUGH		RISER	
	(1987)	64		52		37		42		55		41	
	(1989)	15		4		12		14		22		8	

- NO APPARENT CORRELATION

Table 2.3-10

CHEMICAL ANALYSIS OF STEELS
ADJACENT TO WELD NO. 6 IN THE
INDIAN POINT UNIT 2 STEAM GENERATORS
(From Fabrication Data)

SERIAL NUMBER	MATERIAL SPECIFICATION	LOCATION	HEAT NUMBER	SLAB NUMBER	CHEMICAL ANALYSIS, WT. % C	Mn	P	S	Si	Mo
S/G #21 16A5780-1	A302 Gr. B Lukens	Shell	B5012	1	0.20	1.34	0.010	0.020	0.24	0.48
			B5012	2	0.20	1.34	0.010	0.020	0.24	0.46
		Cone	A0042	2	0.20	1.29	0.011	0.020	0.22	0.49
			A0042	4	0.20	1.29	0.011	0.020	0.22	0.49
S/G #22 16A5780-2	A302 Gr. B Lukens	Shell	A0126	3	0.20	1.27	0.013	0.024	0.24	0.48
			A0126	4	0.20	1.27	0.013	0.024	0.24	0.48
		Cone	C1108	2	0.19	1.23	0.019	0.022	0.23	0.48
			A0042	4	0.20	1.29	0.011	0.020	0.22	0.49
S/G #23 16A5780-3	A302 Gr. B Lukens	Shell	A0877	2	0.18	1.28	0.010	0.019	0.28	0.48
			A0872	3	0.20	1.28	0.015	0.015	0.21	0.47
		Cone	C1108	1	0.19	1.23	0.010	0.022	0.23	0.48
			B4873	5	0.20	1.35	0.008	0.018	0.25	0.47
			B5010	1	0.19	1.26	0.008	0.025	0.22	0.49
S/G #24 16A5780-4	A302 Gr. B Lukens	Shell	A0877	4	0.18	1.28	0.010	0.019	0.28	0.49
			B5973	2	0.20	1.28	0.009	0.019	0.24	0.47
		Cone	C148[illegible]	4	0.19	1.35	0.008	0.018	0.19	0.48
			B5387	1	0.19	1.33	0.011	0.025	0.29	0.48

Table 2.3-11

Table 2.3-12

MECHANICAL PROPERTIES AND TOUGHNESS OF
STEELS ADJACENT TO GIRTH WELD NO. 6 IN THE
INDIAN POINT UNIT 2 STEAM GENERATORS
(From Fabrication Data)

SERIAL NUMBER	MATERIAL SPECIFICATION	LOCATION	HEAT NUMBER	SLAB NUMBER	YIELD STRENGTH (KSI)	TENSILE STRENGTH (KSI)	ELONGATION IN-2 IN %	TOUGHNESS* FT/LBS	LATERAL EXPANSION MILS
S/G #21									
16A5780-1	A302 Gr. B	Shell	B5012	1	68.0	90.5/99.0	30	78/78/79	-
	Lukens		B5012	2	68.2	89/90.9	27	70/87/68	-
		Cone	A0042	2	72.1	95.0/97.0	30	81/74/77	-
			A0042	4	75.4	97.5/95.5	26	55/64/60	-
S/G #22									
16A5780-2	A302 Gr. B	Shell	A0126	3	70.5	94.5/95.5	28	105/97/91	-
	Lukens		A0126	4	64.7	88.1/94.4	30	79/86/64	-
		Cone	C1108	2	64.9	86.6/90.1	31	85/68/97	-
			A0042	4	75.4	97.5/95.5	26	55/64/60	-
S/G #23									
16A5780-3	A302 Gr. B	Shell	A0877	2	66.0	85.3/87.3	30	77/88/97	-
	Lukens		A0872	3	61.9	83.7/83.7	30	79/83/83	-
		Cone	C1108	1	70.3	93.1/90.0	28	81/95/78	-
			B4873	5	64.7	91.5/88.8	26	86/12[illegible]/85	-
			B5010	1	69.0	92.9/92.5	28	93/73/113	-
S/G #24									
16A5780-4	A302 Gr. B	Shell	A[illegible]	4	72.9	93.4/93.0	28	83/92/95	-
	Lukens		B[illegible]	2	71.1	93.9/97.5	28	66/74/70	-
		Cone	C1488	4	73.2	94.9/97.5	27	82/88/89	-
			B5387	1	70.0	90.5/89.5	28	84/84/88	

* Test Temperature = 10°F

0116M:49/010589-19

ASME BOILER AND PRESSURE VESSEL PWHT REQUIREMENTS

MANDATORY AND NON-MANDATORY REQUIREMENTS IN SECTION NB-4620

- BPVC (1968) REQUIRED A MINIMUM HEAT TREATMENT BAND OF 2T EITHER SIDE OF THE WELD AT 1100 DEGREES F FOR ONE HOUR/INCH
  - LOWER TEMPERATURE FOR LONGER PERIODS ACCEPTABLE
- BPVC (1974) REQUIRED A MINIMUM CONTROLLED BAND OF T OR 2 INCHES WHICHEVER IS LESS, EITHER SIDE OF WIDEST WELD WIDTH BE HEAT TREATED BETWEEN 1100/1250 DEGREES F
  - TIME AT TEMPERATURE
    - 2 HRS PLUS 15 MINUTES FOR EACH ADDITIONAL INCH OVER 2 INCH
    - LOWER TEMPERATURE FOR LONGER TIME ACCEPTABLE

Table 2.3-13

- P-3 GRADES USED HAVE PROPERTIES DEVELOPED DURING TEMPERING HEAT TREATMENTS AT TEMPERATURES IN THE RANGE OF 1200/1250 DEGREES F
  - NO PWHT PERFORMED AT OR NEAR THIS RANGE
- WESTINGHOUSE SPECIFICATION FOR LOCAL PWHT OF S/G CLOSURE WELD REQUIRE A SOAK TEMPERATURE OF 1125 DEGREES ± 25 DEGREES F FOR A PERIOD OF 4 HOURS
  - HEATING/COOLING RATE ABOVE 800 DEGREES F SHALL BE 100 DEGREES F/HR.
  - LOWER TEMPERATURE FOR LONGER PERIODS OF TIME ARE PERMITTED
    - 1050 DEGREES F MIN. FOR 12 HRS
    - 1000 DEGREES F MIN FOR 18 HRS.

Table 2.3-13 (Cont.)

- PWHT (MFG FACILITY OR FIELD) FOLLOWED ABOVE SPECIFICATION USING PORTABLE EQUIPMENT

  - FACTORY PWHT PERFORMED IN PORTABLE "CALM SHELL" FURNACE, VESSEL IN A HORIZONTAL POSITION

- REVIEW OF A TOTAL OF 44 CLOSURE WELD HEAT TREAT CHARTS (INCLUDE 19 FIELD PWHT) DURING 1969 - 1978

  - 19 BETWEEN 1000 DEGREES - 1030 DEGREES F

  - 1 BETWEEN 1000 DEGREES - 1050 DEGREES F

  - 8 BETWEEN 1050 DEGREES - 1100 DEGREES F

  - 16 BETWEEN 1050 DEGREES - 1085 DEGREES F

- PWHT OF CLOSURE WELDS AFTER 1978 WERE CONTROLLED IN THE 1100/1150 DEGREES F RANGE

Table 2.3-13 (Cont.)

MATERIAL OF CONSTRUCTION

FOR CONE/SHELL AREA FOR IPP STEAM GENERATORS

MATERIAL: A-302 GRADE B

WELD PRACTICE: MANUAL STICK

WELD METAL: ASTM - A-233 TYPE 8018

PREHEAT: 225°F MINIMUM

INTERPASS: 500°F MAXIMUM

PWHT: SOAK TEMPERATURE (AND HENCE SOAK TIME) MINIMUM TEMPERATURE ATTAINED BY ANY ONE THERMOCOUPLE WHEN MAXIMUM TEMPERATURE IS 1150°F.

MIN. TEMP.	WHEN MAX.TEMP.	HOLD TIME
1100°F	1150°F	3-1/2 HRS.
1050°F	1150°F	7 HRS.
1000°F	1100°F	10-1/2 HRS.

Table 2.3-13 (Cont.)

PREHEAT TEMPERATURE SUMMARY FOR GIRTH WELD NO. 6 IN THE INDIAN POINT 2 STEAM GENERATORS

GENERATOR	PREHEAT	COMMENTS
21	250°F - 350°F	NO UNUSUAL TEMPERATURE SWINGS
22	275°F - 375°F	NO UNUSUAL TEMPERATURE SWINGS
23	250°F - 350°F	NO UNUSUAL TEMPERATURE SWINGS
24	250°F - 350°F	NO UNUSUAL TEMPERATURE SWINGS

Table 2.3-13 (Cont.)

POST WELD HEAT TREAT TIME AND TEMPERATURE
FOR GIRTH WELD NO. 6 IN THE
INDIAN POINT UNIT 2 STEAM GENERATORS

S/G (DATE PWHT)	TIME AT TEMPERATURE	PWHT EQUIVALENT @ 1125°F ± 25°F (EXPRESSED IN HRS.)
16A5780-1 (5/7/69)	7 HRS. @ 1050°F - 1150°F (3 HRS. 35 MINUTES @ 1125°F ± 25°F)	3.60
16A5780-2 (4/18/69)	12 HRS. @ 1025°F - 1150°F (4 HRS. 15 MINS. @ 1125°F ± 25°F	4.25
16A5780-3 (4/25/69)	7 HRS. 30 MINS. @ 1050°F - 1150°F (3 HRS. 45 MINS. @ 1125°F ± 25°F)	3.75
16A5780-4 (4/12/69)	12 HRS. @ 1000°F - 1150°F (4 HRS. 10 MINS. @ 1125°F ± 25°F)	4.15

Table 2.3-13 (Cont.)

2.4 Feedwater Thermal Hydraulics

This section provides the basis for the thermal hydraulic boundary conditions used to perform the stress and fatigue analyses for the girth weld region (Table 2.4-1). It begins with a presentation of the enveloping transient conditions established previously in WCAP-11730, completed for the Fall 1987 Outage when girth weld indications were first detected. The current evaluations are consistent with the 1987 evaluation.

Two conditions, reactor trip (RT) and feedwater cycling (FWC)[1], are identified as the most limiting conditions since they cause significant temperature changes to the girth weld region. The auxiliary feedwater flow that is associated with each of these conditions is described in text and graphically illustrated in the figures. The flow of auxiliary feedwater in the generator, and specifically the impingement of the flow on the girth weld, is shown to be directly related to the position of the downcomer flow resistance plate (DCRP). The flow path, degree of mixing, and temperature of the water as it strikes the shell are best estimate thermal hydraulic calculations. It is recognized that there is some uncertainty associated with this description as neither direct measurements nor test data are available. In addition, another associated loading mechanism is postulated, i.e., thermal striping, in a later section that could significantly contribute to fatigue usage.

The section concludes with the recognition that water level control and water temperature control would have a direct influence on girth weld fatigue.

Table 2.4-2 presents the umbrella transient events used for the design basis evaluation of fatigue usage. It is the same basis as used previously in WCAP-11730 for the 0.75 inch and 1.0 inch groove models and is the basis for the evaluation of two new models with 0.5 inch and 1.25 inch grooves. All conditions involve stress changes due to pressure while two of the events, reactor trip and feedwater cycling also cause stress changes due to temperature changes at the girth weld.

[1]Feedwater cycling is the title given to auxiliary feedwater injection at zero power, hot standby conditions, to control water level.

Recognizing that cracking recurred in just one fuel cycle, a review of Indian Point 2 operating conditions since startup was made to compare the last fuel cycle history of events to the prior years. This comparison is provided in Table 2.4-3 which shows that the last fuel cycle was equivalent to or less severe than the averages for prior years. It also shows that reactor trip and hot standby (feedwater cycling) are the most significant events, excluding heatup and cooldown which are less severe conditions.

The thermal hydraulic boundary conditions for reactor trip and feedwater cycling used in the prior evaluations (WCAP-11730) and in the analysis of the two new models are described in Table 2.4-4. Following that is a schematic illustration (Figure 2.4-1) of the upper part of the steam generator (shown without the DCRP). Figure 2.4-2 is a copy of a portion of the steam generator assembly drawing showing the DCRP located adjacent to the girth weld.

A bounding condition is assumed for the purpose of analysis to occur during the reactor trip. The water level is assumed to drop well below the girth weld region. This permits the auxiliary feedwater that automatically is injected within a short time [

]^{a,c} Figure 2.4-2 shows the current position of the DCRP within 1 or 2 inches of the girth weld centerline. Figure 2.4-4 shows how [

]^{a,c} Figure 2.4-5 shows [

]^{a,c} This last sketch illustrates the boundary condition analyzed for the reactor trip transient. This condition may not normally occur in the sense that the water level may not be that low when auxiliary feedwater enters the generator. [

]^{a,c} In that case, the conditions analyzed should be very similar.

During feedwater cycling, the water level is approximately 7.0 inches above the feedwater ring and a best estimate calculation indicates [

]a,c Again, it is possible that the feedwater

[

]a,c If that is the case, the design basis analysis would under predict the fatigue usage.

For stretch conditions, the expected water level during normal operation and during reactor trip and at hot standby is slightly lower than in the non-stretch (current) condition. The bounding condition assumed for analysis is not affected by this difference. If the actual conditions experienced at the girth weld are different than the assumed analysis conditions, the water level difference with stretch is judged to be small enough to have no efffect on the girth weld.

The importance of the cold water thermal hydraulics to the boundary conditions used in the fatigue evaluation has been illustrated. Any internal or system modification that would result in avoiding [

]a,c at the girth weld would be beneficial as would any change that would lessen the temperature difference between the hot and cold fluids (Table 2.4-5).

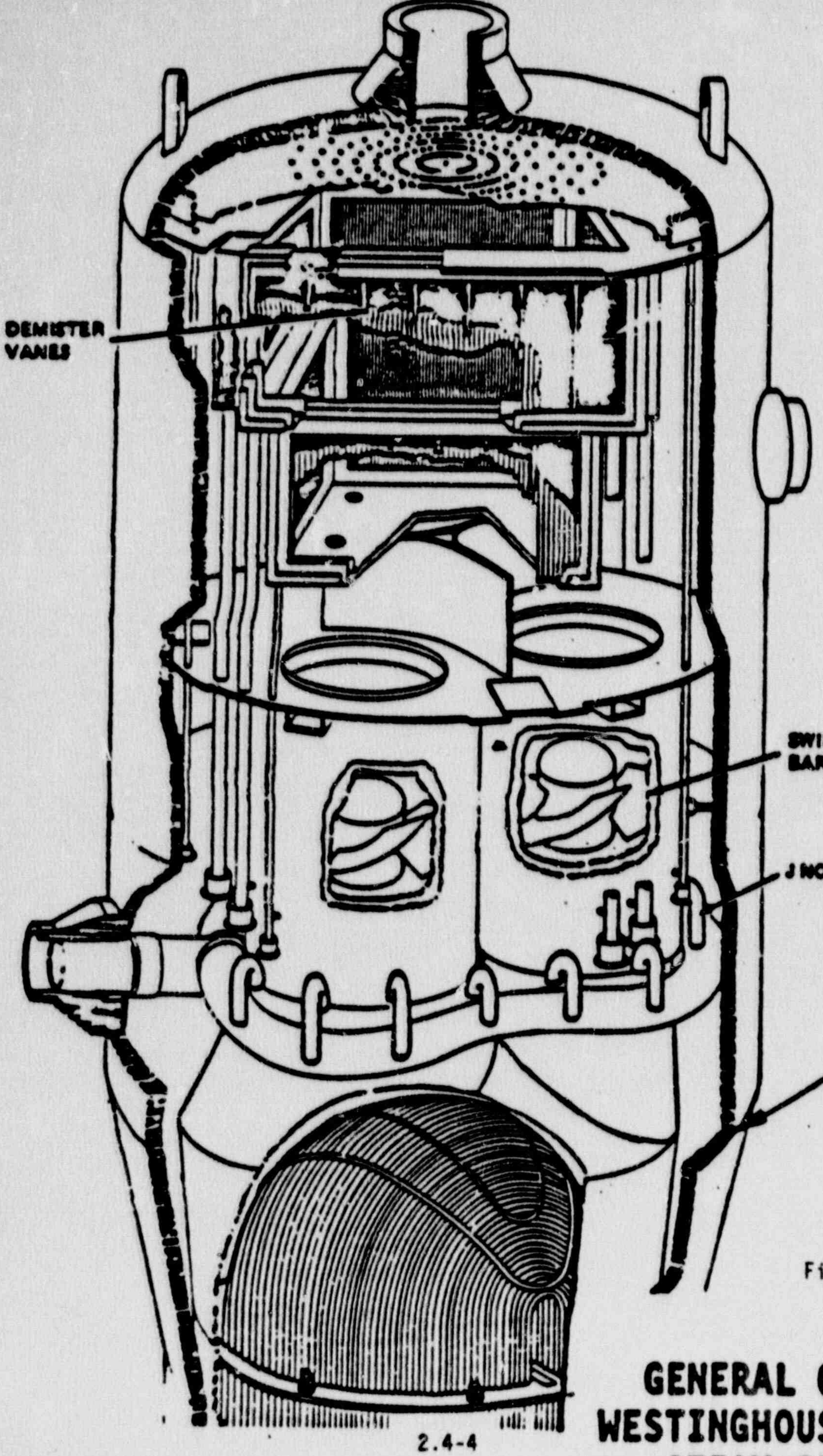
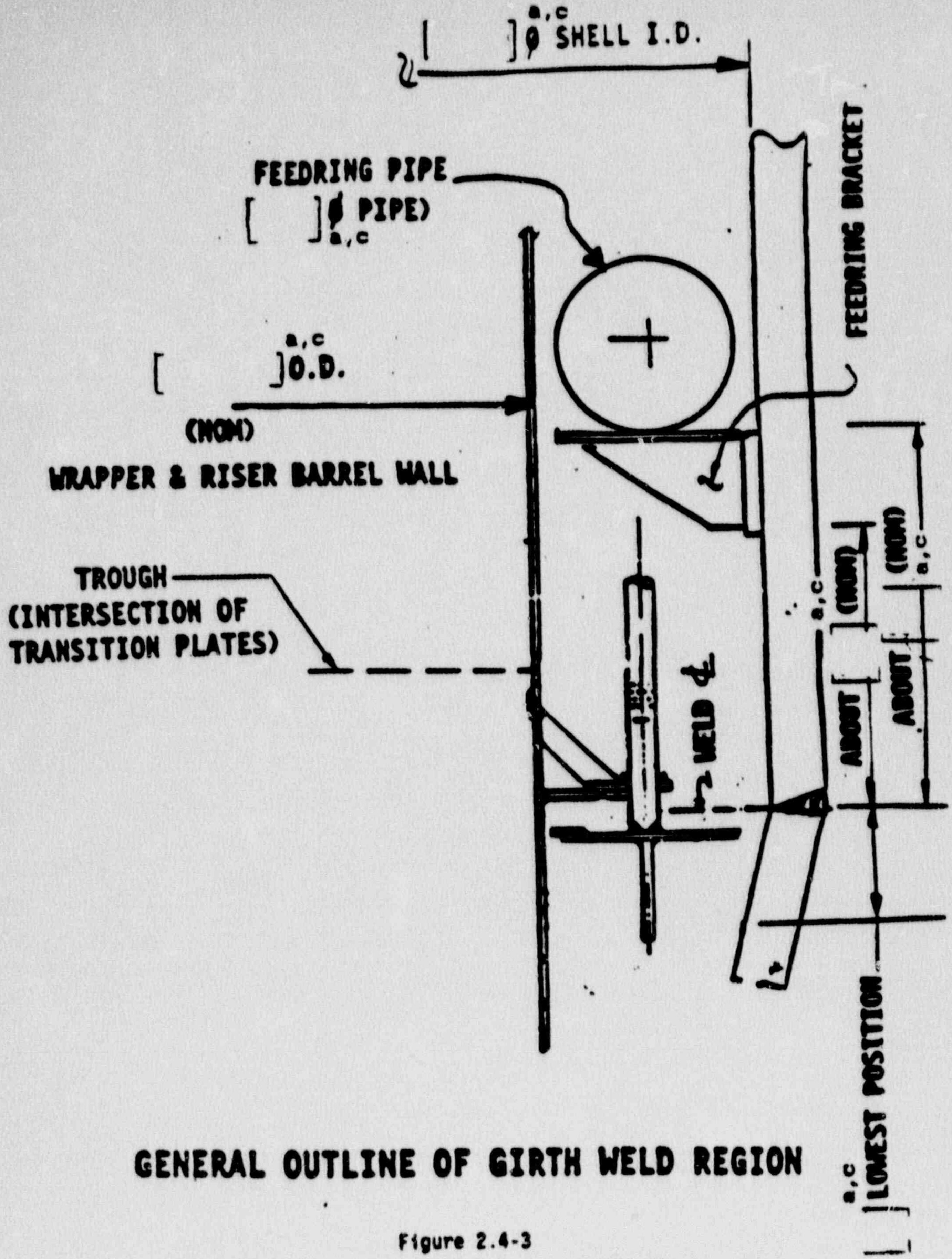


Figure 2.4-1

GENERAL OUTLINE OF WESTINGHOUSE MODEL 44 STEAM GENERATOR

a,c

Figure 2.4-2



GENERAL OUTLINE OF GIRTH WELD REGION

Figure 2.4-3

a,c

GENERAL OUTLINE OF GIRTH WELD REGION

Figure 2.4-4

a,c

GENERAL OUTLINE OF GIRTH WELD REGION

Figure 2.4-5

FEEDWATER THERMAL HYDRAULICS

IDENTIFICATION OF CRITICAL TRANSIENTS

WATER LEVEL CONSIDERATIONS

AUXILIARY FEEDWATER FLOW PATHS

RECOMMENDATIONS FOR MITIGATION

Table 2.4-1

INDIAN POINT 2 (IPP)
UMBRELLA TRANSIENT CONDITIONS

TRANSIENT	CYCLES a,c
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	

NOTE: a,c

Table 2.4-2

TABLE - 3

IPP TRANSIENT EVENTS BREAKDOWN BETWEEN '71 TO '88 AND '88 TO '89

SRL NO	DESCRIPTION OF TRANSIENTS	NUMBER OF TRANS. OCCURRENCES '71-'89	'88-'89	'71-'88	AV EVENTS PER YEAR '71-'88	AV EVENTS LAST YEAR '88-'89	AV EVENTS PER YEAR '71-'89
	YEARS OF SERVICE --->	16.21	1.21	15.00			
1	SMALL STEP LOAD DECREASE	50	1	49	3.27	0.83	3.08
2	SMALL STEP LOAD INCREASE	42	0	42	2.80	0.00	2.59
3	LARGE STEP LOAD DECREASE	34	0	34	2.27	0.00	2.10
4	HEATUP	76	6	70	4.67	4.97	4.69
5	COOLDOWN	76	6	70	4.67	4.97	4.69
6	HOT STANDBY (IN HOURS)	9,764	415	9,349	623.27	343.45	602.41
7	REACTOR TRIP **	482	6	476	31.73	4.97	29.74

** INCLUDES LOL, LOP, CRD, PLOF

Table 2.4-3

THERMAL TRANSIENT BOUNDARY CONDITIONS
REACTOR TRIP AND FEEDWATER CYCLING TRANSIENTS

REACTOR TRIP

a,c

[ ]

FEEDWATER CYCLING

a,c

[

D]

Table 2.4-4

FEEDWATER THERMAL HYDRAULICS

Recommendations For Mitigation

Control Water Level

Provide Heated Water

Table 2.4-5

2.5 Fatigue Usage Evaluations

With a corrosion fatigue mechanism, it is imperative that the important initiating loading conditions are addressed in a fatigue usage evaluation that uses representative stress amplitudes. To this end, the following section presents the results of three different usage calculations. It also addresses the removal of the DCRP and its impact on these fatigue usages (Figure 2.5-1).

The first evaluation provides fatigue usages for four different grooved geometries using the 40 year design basis transients and the ASME Code Design Fatigue Curve. The second evaluation makes the assumption that the Code fatigue curve is not representative of the material in this environment and computes fatigue usages for these geometries for comparison. The third analysis introduces an additional potential loading mechanism, thermal striping, to illustrate qualitatively its potential effect on fatigue life. Based on the change in thermal boundary conditions that should result by removing the DCRP, the fatigue usages of the second analysis are reevaluated to demonstrate the impact. Finally, the beneficial effect that this would have with regard to thermal striping is addressed.

2.5.1 Cold Water Level Cases

Of all the loading transients the girth weld area experiences, two transients: reactor trip and feedwater cycling (at hot standby) are the most important. With the downcomer flow resistance plate in place, the secondary side water level during reactor trip is assumed to be [ ]^{a,c} as shown in Figure 2.5-2. With the DCRP removed, the cold water is estimated to [ ]^{a,c} Conservatively, the cold water level may be considered to be [ ]^{a,c} For the feedwater cycling at hot standby, the water level is [ ]^{a,c}

2.5.2 Structural Analysis Models

Structural analyses were performed for four different groove depth configurations. Groove depths are 0.50, 0.75, 1.00, and 1.25 inches. Of these, the 0.75 and 1.00 inch groove depths were evaluated previously in the Westinghouse Report WCAP-11730. The height of land at the bottom of the groove is greater for the shallower grooves (0.50 and 0.75) than for the deeper grooves (1.00 and 1.25). The whole conical shell section in addition to adequate lengths of upper and lower shells were modeled for finite element analysis by using axisymmetric isoparametric elements. WECAN, a generalized finite element program developed by Westinghouse, was used in the analysis. The mesh configuration at the groove area of various models is shown in Figures 2.5-3 to 2.5-7. The ASN numbers in these figures indicate the sections where stresses and fatigue usage factors were evaluated.

2.5.3 Stress and Fatigue Results

The stress components for membrane as well as membrane plus bending stress categories for these two important transients are shown in Table 2.5-1 for all the models at the critical sections The stresses are shown here to provide a stress comparison of the four models. It shows that there is a fairly uniform reduction in stress with decreasing groove depth. The stress limits for the 0.75 inch and 1.0 inch groove models are shown to be satisfied in WCAP-11730.

The fatigue usage factors for a forty year design life objective are computed for all applicable loading combinations as previously defined. The results are presented in Table 2.5-2. The figure just below the table gives a comparison of fatigue usage levels at the girth weld area and the straight region within the groove. This plot shows the relative insensitivity of fatigue usage to groove depth for the conditions evaluated on a forty year basis. Obviously, the absolute values of usage have minimal value since the usage factors equate to nearly 20 years of service before reaching a usage of 1.0, but is included here for the purpose of determining the degree of sensitivity of fatigue usage to groove depth with the design basis.

2.5.4 Accelerated Fatigue Usage Evaluation for the Last Operating Cycle

Consequent to the fact that cracks appeared after only one operating cycle, it is reasonable to assume that some kind of accelerated fatigue action was in motion during the last operating cycle. A review of the operating history as summarized in the Tables 2.5-3 and 2.5-4, indicates that the steam generators were at hot standby 8 times for a total of 415 hours during the last 14.5 months of operation, and it experienced a total of 6 reactor trip events.

An accelerated fatigue diagram was obtained so that a fatigue usage of 1.0 would be predicted in the grooved girth weld area. This accelerated fatigue diagram is based to some extent on the test results obtained for welded and virgin SA-106 Grade B material with and without notches in the PWR environment at 550°F. The equation applicable for a number of fatigue diagrams are given in Table 2.5-5. These diagrams are shown in Figure 2.5-8 on a log-log plot. The accelerated fatigue diagram chosen is diagram C in the figure.

The fatigue usage for the last fuel cycle is estimated on the basis of the accelerated fatigue diagram C. Since the exact number of the feedwater cycles is not known, the results were obtained for three different sets of feedwater cycles in conjunction with the reactor trip events. The results for only the reactor trip events were also obtained for comparison purposes. The results are given in Table 2.5-6 and graphically below the table. The results show that a groove depth of 1.0 inch provides an improvement of about 25% on the fatigue usage over the 1.25 inch configuration. The additional improvement with the 0.75 inch configuration compared to the 1.0 inch is a modest 13%. Beyond 0.75 inch, the additional improvement is still less.

2.5.5 Estimate of the Impact of Thermal Striping

Thermal striping is a high frequency temperature oscillation that occurs in water at regions of mixing or at the interface between hot and cold fluids. This additional loading mechanism is postulated as a result of the small, fatigue striation spacing observed in the boat sample examinations. Although an unconfirmed mechanism in this region of the generator, it is a possible loading mechanism and if present could lead to a significant accumulation of cycles in a single fuel cycle. The probable condition of cold water being [

]^{a,c} setting up the conditions for striping to occur. Our experience is that such a condition would need to be established by direct measurement or by data taken in a test model. Both are very difficult to accomplish but necessary if quantitative confirmation of the loading mechanism is desired.

A description of the characteristics of striping is provided along with examples of test measurements illustrating the temperature fluctuations (Table 2.5-7 and Figures 2.5-9 through 2.5-10). A precise treatment of the stress response involves a time history representation of the temperature and the associated metal heat transfer solution (Figures 2.5-11 and 2.5-12). This has been successfully approximated by [ ]^{a,c} approach which results in stress amplitudes for the ranges of potential film coefficients and frequencies that may exist (Table 2.5-8). By using the stress amplitude response versus frequency plot (Figure 2.5-13) and the high cycle fatigue curve for this material from the ASME Code (Figure 2.5-11), one can demonstrate that for some film coefficients, significant fatigue usage can be accumulated in a fuel cycle. This would require a steady flow rate for extended periods of time, however, and it has not been shown that Indian Point 2 operation is consistent with this scenario. On the other hand, it is possible that thermal striping may be occuring [

]^{a,c}

Thermal striping may be a contributor to crack initiation and even to some propagation but quantifying this would be very difficult. Removal of the DCRP is one means of eliminating this loading mechanism, however, [

]^{a,c} (Table 2.5-9).

2.5.6 Effect of Removing the DCRP

Removing the downcomer flow resistance plate permits the cold water [

]^{a,c} (Figure 2.5-15). Stretch conditions have no effect on this expected behavior. This would occur either with [

]^{a,c}

As just described, its removal should eliminate the potential for striping to occur and its removal should also provide a benefit to the fatigue usage accumulated from the normal duty cycle. It is estimated that the cold water would strike the shell [

]^{a,c} Assuming that the cold flow [

]^{a,c} Case 1 presented earlier, the benefit to the girth weld critical location is on the order of a factor of three or four on fatigue usage (Table 2.5-10). This means, for example, that if crack initiation occurred in four months during the last fuel cycle, then twelve to sixteen months would now be required. The fatigue usage at the elevation of the cold water impingement (just below the groove) is less than one-tenth of the fatigue usage of the critical location within the groove.

FATIGUE USAGE EVALUATIONS

Prior Thermal Hydraulic Basis

Estimated Impact of Striping

Removal of Downcomer Plate

Recommendations For Mitigation

Figure 2.5-1

a,c

Figure 2.5-2

REACTOR TRIP BOUNDARY CONDITIONS CONSIDERED
TYPICAL FOR BOTH 1.0" AND 3/4" GRIND MODELS

a,c

Figure 2.5-3

FINITE ELEMENT MODEL FOR 1.0" GRIND

a,c

Analysis Section Locations 0.50" Grind Model

Figure 2.5-4

a,c

Figure 2.5-5

ANALYSIS SECTION LOCATIONS
0.75" GRIND MODEL
a,c

a,c

Figure 2.5-6

ANALYSIS SECTION LOCATIONS
1.0 " GRIND MODEL

a,c

Analysis Section Locations 1.25" Grind Model

Figure 2.5-7

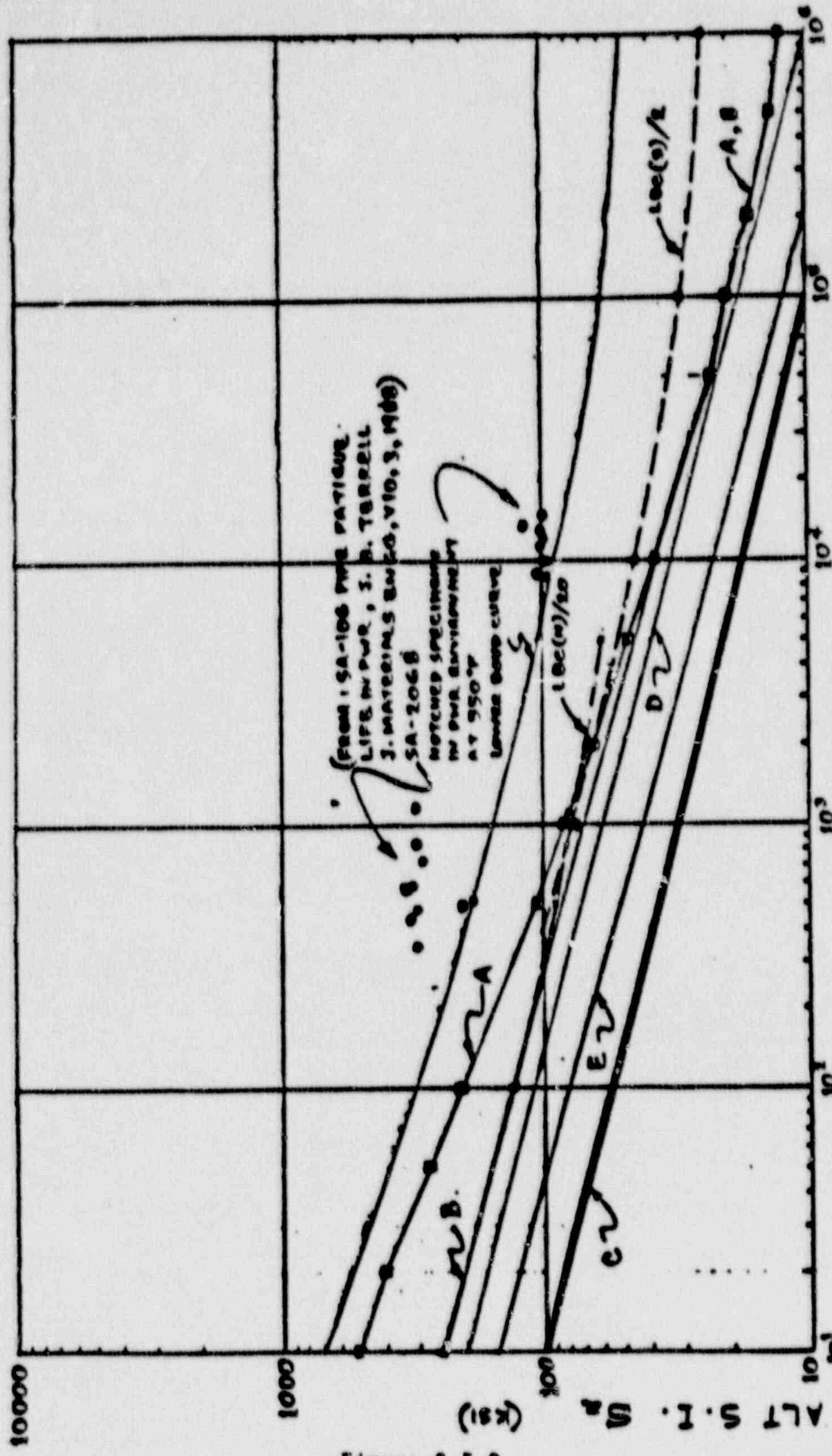


Figure 2.5-8

a,c

Figure 2.5-9 CASE NO.20, FLOW TEST TEMPERATURE RECORD

a,c

Figure 2.5-10, CASE NO.22, FLOW TEST TEMPERATURE RECORD

a,c

Figure 2.5-11 CASE NO. 20 SURFACE STRESS TIME HISTORY.

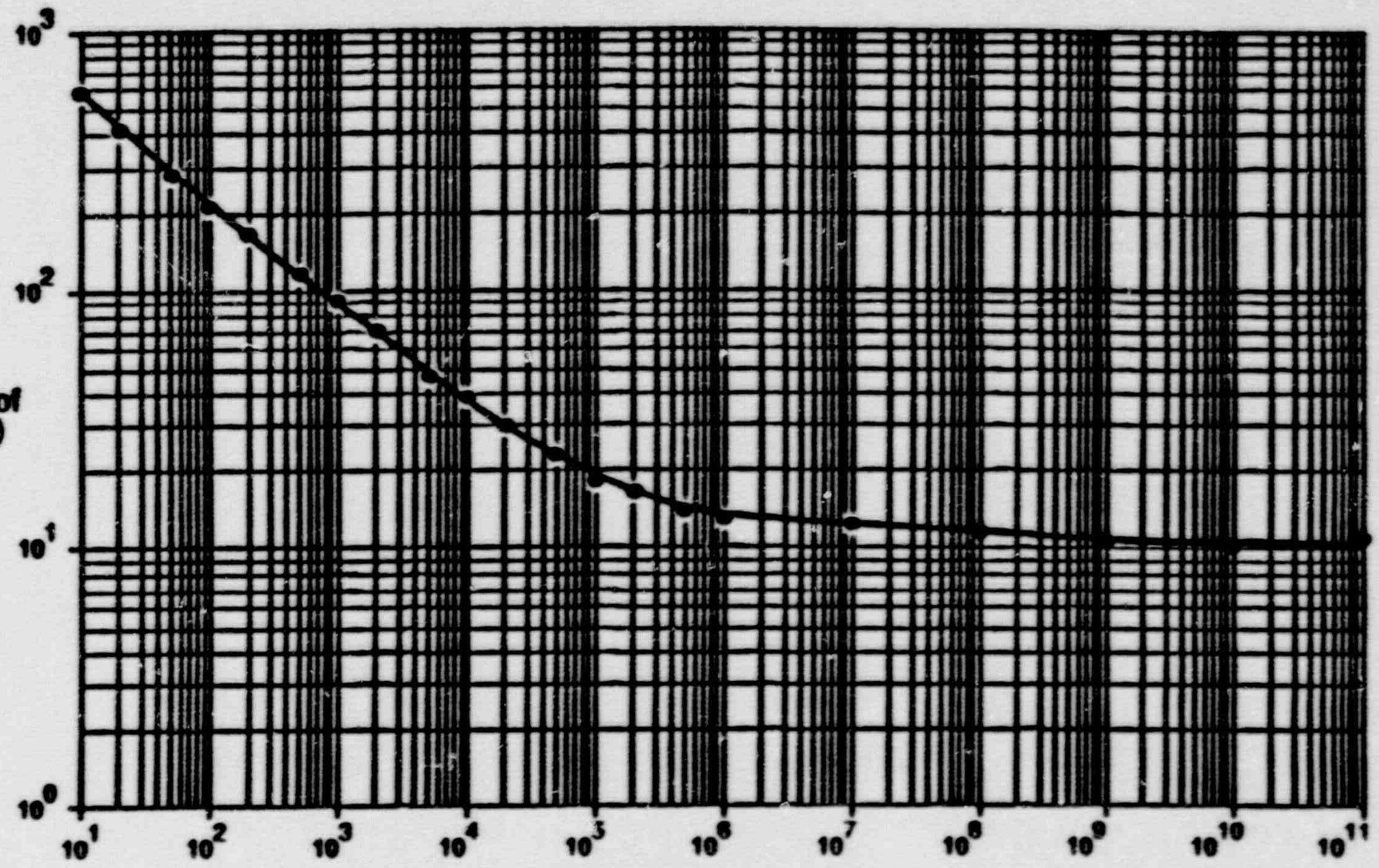
a,c

Figure 2.5-12 **CASE NO. 22 SURFACE STRESS TIME HISTORY.**

a,c

FIGURE 11C-15: MAXIMUM STRESS. N = [ ] a,c
THICKNESS = [ ] a,c

Figure 2.5-13



Design Fatigue Curves for Carbon, Low Alloy, and High Tensile Steels
for Metal Temperatures Not Exceeding 700°F

Figure 2.5-14

a,c

GENERAL OUTLINE OF GIRTH WELD REGION

Figure 2.5-15

SUMMARY OF GIRTH WELD STRESSES IN GRIND REGION

a,c

Table 2.5-1

SUMMARY OF FATIGUE USAGES

INDIAN POINT GIRTH WELD

ASME CODE FATIGUE CURVE

	LOCATION OF HIGHEST USAGE			GROOVE STRAIGHT REGION		
GRIND DEPTH	ASN	NODE	USGAE	ASN	NODE	USAGE
0.50"	12	608	1.51	18	664	0.13
0.75"	13	508	1.94	18	638	0.16
1.00"	14	534	2.08	17	612	0.61
1.25"	13	534	2.26	16	612	0.54

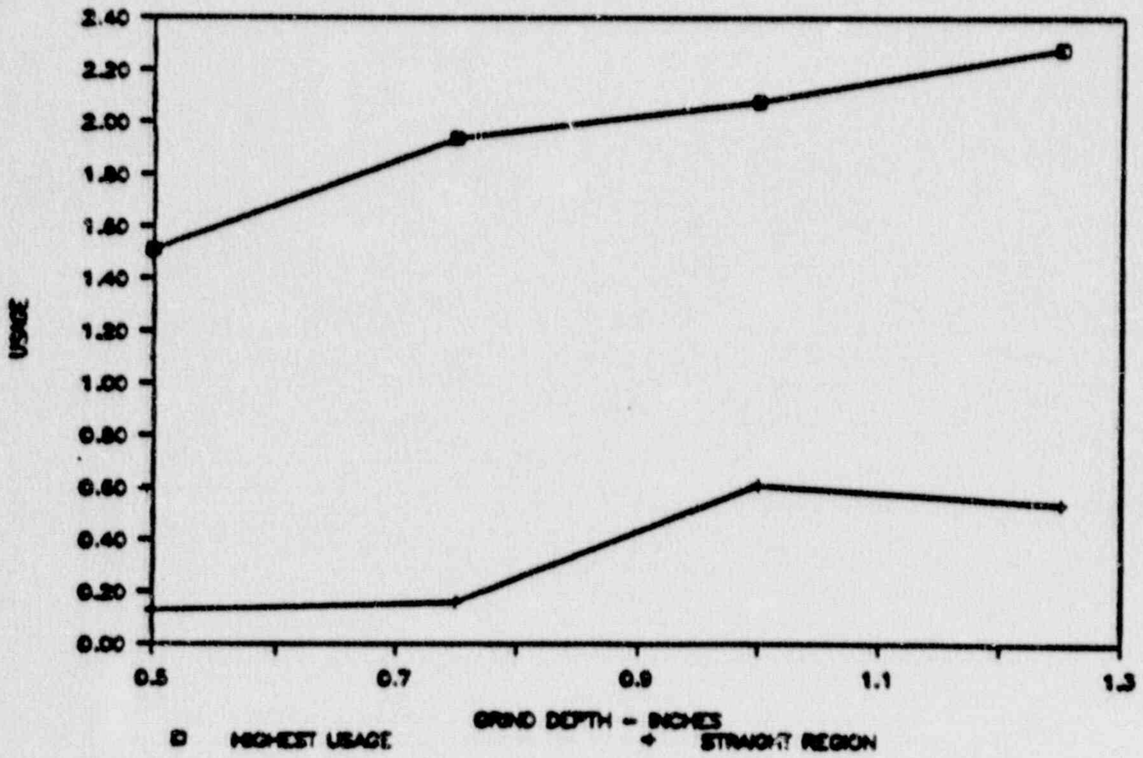


Table 2.5-2

TABLE - 1

IPP TRANSIENTS HISTORY BETWEEN 87/88 & 3/89 OUTAGES

DATE OCCUR	DESCR. OF TRANSIENTS	COMMENTS
5/22/88	SMALL STEP LOAD DECREASE	100-96%
1/5/88	HEATUP	205-541F
1/14/88	HEATUP	342-500F
1/16/88	HEATUP	300-542F
6/24/88	HEATUP	140-547F
7/20/88	HEATUP	120-547F
9/28/88	HEATUP	336-546F
1/13/88	COOLDOWN	547-342F
1/16/89	COOLDOWN	500-300F
6/17/88	COOLDOWN	547-140F
7/7/88	COOLDOWN	547-120F
9/24/88	COOLDOWN	547-336F
3/17/89	COOLDOWN	547-120F
8 TIMES	HOT STANDBY	TOTAL 415.25 HOURS
1/25/88	REACTOR TRIP	10%
2/9/88	REACTOR TRIP	16%
6/17/88	REACTOR TRIP	100%
11/22/88	REACTOR TRIP	100%
11/26/88	REACTOR TRIP	100%
2/28/89	REACTOR TRIP	100%

Table 2.5-3

TABLE - 2

IPP TRANSIENT EVENTS BETWEEN 87/88 OUTAGE AND 3/89 OUTAGE *

SRL NO	DESCRIPTION OF TRANSIENTS	NO OCCUR.	COMMENTS
1	SMALL STEP LOAD DECREASE	1	
2	SMALL STEP LOAD INCREASE	0	
3	LARGE STEP LOAD DECREASE	0	
4	HEATUP	6	
5	COOLDOWN	6	
6	HOT STANDBY	8	TOTAL 415 HOURS
7	REACTOR TRIP	6	4 FROM FULL POWER

* TOTAL PERIOD 14.5 MONTHS (1/5/88 HEATUP TO 3/17/89 COOLDOWN)

Table 2.5-4

a,c

Table 2.5-5

IPP GIRTH WELD - ESTIMATE OF LAST FUEL CYCLE FATIGUE USAGE WITH DCR PLATE

GROOVE DEPTH	WATER LEVEL	6 RT'S + FW CYCLING			RT ONLY
		8 FW	40 FW	208 FW	
0.5	CASE 3	1.03	1.06	1.2	1.02
0.75	CASE 3	1.03	1.08	1.35	1.02
1	CASE 3	1.19	1.25	1.55	1.18
1.25	CASE 3	1.63	1.7	2.03	1.62

LAST FUEL CYCLE FATIGUE USAGE

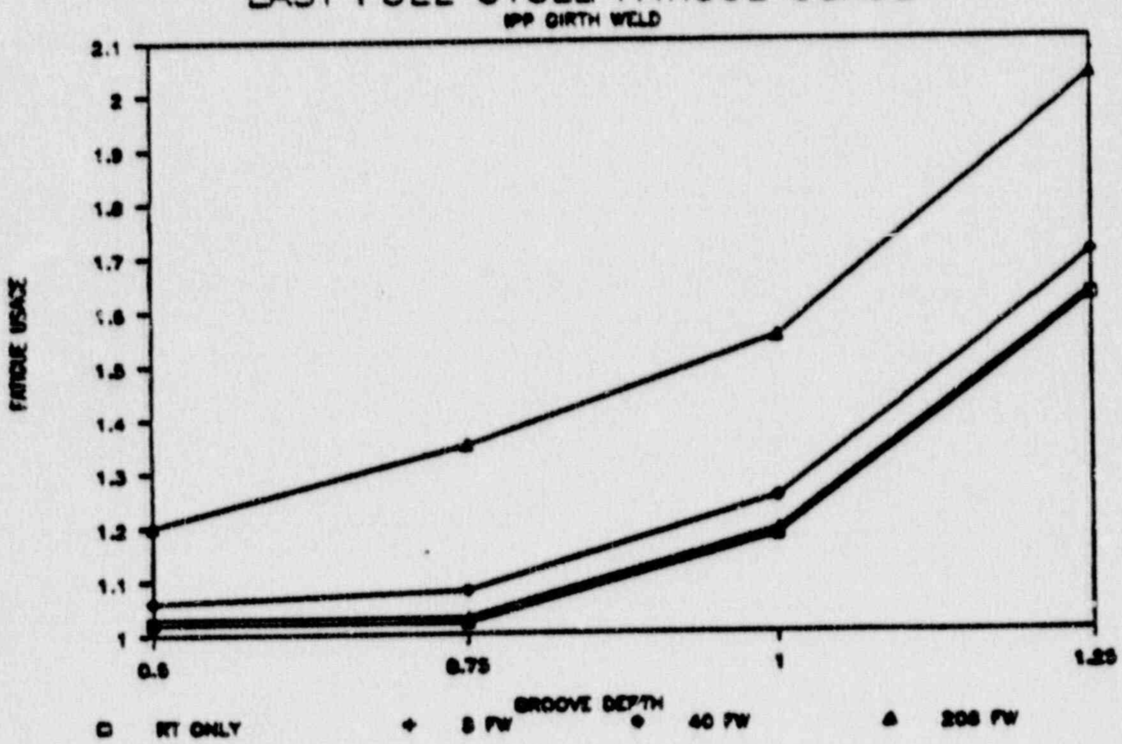


Table 2.5-6

ESTIMATE OF IMPACT OF THERMAL STRIPING

a,c

Table 2.5-7

TABLE 11C.1

SUMMARY OF INPUT FOR
TEMPERATURE STRIPING ANALYSIS

a,c

Table 2.5-8

CONCLUSIONS REGARDING THERMAL STRIPING

Difficult to quantify

May be a contributing factor to crack initiation and growth

Best eliminated by removing downcomer plate

Table 2.5-9

IPP GIRTH WELD - ESTIMATE OF NEXT FUEL CYCLE FATIGUE USAGE WITHOUT DCR PLATE

GROOVE DEPTH	WATER LEVEL	6 RT'S + FW CYCLING 8 FW	40 FW	208 FW	RT ONLY
0.5	CASE 1				
0.75	CASE 1	0.25	0.3	0.57	0.24
1	CASE 1	0.24	0.3	0.6	0.23
1.25	CASE 1	0.29	0.35	0.68	0.27

Table 2.5-10

2.6 Downcomer Plate History

Because feedwater valve wear and reactor control rod wear may result from continuous efforts to control a fluctuating steam generator water level, a hydrodynamically stable steam generator is desirable (Table 2.6-1).

Steam generator stability is a function of power level, circulation ratio, pressure, amount of subcooling, and the ratio of the single phase to two-phase pressure drops in the recirculation loop. Because an increase in two-phase pressure drop moves a stable steam generator closer to the point of instability and an increase in single phase pressure drop is more stabilizing, downcomer flow resistance plates were incorporated into steam generator designs because these downcomer flow resistance plates produce single phase pressure drop, and thus tend toward steam generator hydrodynamic stability (Figure 2.6-1).

However, in the late 1970s, downcomer flow resistance plates were removed from many operating steam generators to increase tube bundle flow, therefore reducing the size of tubesheet sludge piles (Table 2.6-2). In any event, the stability or damping factor for Indian Point 2, reduced by downcomer flow resistance plate removal, is still significantly higher than other stable operating plants that have had their downcomer flow resistance plates removed. No Westinghouse 44 Series steam generator has ever exhibited unstable operating characteristics with, or without, downcomer flow resistance plates (Figure 2.6-2 and Table 2.6-3).

Many plants have removed downcomer flow resistance plates and have not had cracking. [ ][g], plants C and D has removed downcomer flow resistance plates and has not had a recurrence of cracking. [ ][g], plant A had removed downcomer flow resistance plates prior to finding girth weld cracking (Table 2.6-4 and -5).

The downcomer flow resistance plate in the 51 Series steam generator is positioned 30 inches below the girth weld centerline. Also, the top of the wrapper (the trough region between the riser barrels) is just below the girth elevation. In this configuration, removal or retention of the DCRP would probably have much less effect on the potential for girth weld cracking than in the 44 Series steam generator. This is due to the expected impingement location of cold water being well below the girth weld (with or without the impingement plate) and thus the thermal discontinuity is at a different elevation (lower) than the structural discontinuity at the girth weld.

In the case of a Model 51F, the DCRP is positioned slightly above the girth weld centerline. As in the case of the 44 Series, the removal of the DCRP would be beneficial to the potential for girth weld cracking in the Model 51F, given the postulated thermal hydraulic boundary conditions. With the DCRP, the thermal and structural discontinuities are nearly coincident. Without the DCRP, they are separated.

2.6.1 Impact of DCRP Removal On U-Bend Fatigue

An evaluation has been performed to determine the effects of removing the DCRP on the previously completed U-bend fatigue (North Anna R9C51) evaluations.

Steam generator operating parameters for the existing Indian Point Unit 2 steam generators operating at the 100 percent power level are given in Table 2.6-6. To support the uprating analysis, operating conditions were also determined for the thermal-hydraulic input defining an 11.8 percent increase in power, and a plugging level of 25 percent. In order to meet performance and structural requirements, a higher (591°F) steam generator inlet temperature was used to produce the minimum acceptable tube bundle pressure value of 650 psia, and was chosen for use in this analysis. The resulting 'Uprate' design conditions are also given in Table 2.6-6.

In setting operating conditions for the three dimensional ATHOS tube bundle flow analysis, the objective was to permit the minimum possible delivered steam pressure. This in turn would allow the maximum plant operating flexibility at low primary temperatures and high plugging levels. With the 650 psia minimum pressure constraint on the bundle pressure, the minimum allowable steam nozzle outlet pressure is 641 psia. The difference between 641 psia and 650 psia is the pressure drop between the bundle and the outlet nozzle. Instrument uncertainties have not been considered.

Table 2.6-6 indicates that, based on the current configuration with downcomer resistance plates installed, a circulation ratio of [ ]^{a,c} is calculated. If the plates are removed, the resulting decrease in circulation loop pressure loss leads to a [ ]^{a,c} increase in the circulation ratio [ ]^{a,c} and the total bundle flow rate. The magnitude of this change is relatively small because the plates are currently assumed to be located at the uppermost point in the positioning span. At this location, the bypass flow area within the wrapper-to-shell annulus is maximized and, as a result, the plate has only a small influence on the loop hydraulics.

The basis for the reference 3D ATHOS flow field and tube stability ratio analyses is the uprated operating conditions listed in Table 2.6-6, including a circulation ratio of [ ]^{a,c} which corresponds to the current configuration with downcomer resistance plates installed. The small incremental effect of removing the plates on stability ratios is accounted through use of a 1D relative stability ratio adjustment factor. The 1D adjustment provides a method of accounting for the effect of differences in operating conditions on stability ratio. In particular, it provides a means of generating simulated 3D stability ratios for an alternate set of operating conditions without having to complete a specific, detailed 3D flow field calculation. A discussion of the 1D relative stability ratio calculation technique was provided in Section 7.4 in WCAP 11811. Using this technique an adjustment factor of [ ]^{a,c} was calculated. The [ ]^{a,c} increase represents the incremental effect of removing the downcomer resistance plates.

Justification for use of a simplified, one-dimensional, relative stability ratio adjustment factor is provided by making comparisons with the results obtained from more detailed three-dimensional flow field/tube vibration calculations. The attached Figure 2.6-3 presents the comparison of the results of the two calculation methods for ten other 51, 44, and 27 Series generators which have been evaluated, to date. The three-dimensional results are based on use of bundle flow fields predicted with the ATHOS3 computer code.

Both cylindrical and Cartesian models have been used in the ATHOS3 simulations. Note that the results plotted in Figure 2.6-3 do not include the effects of anti-vibration bars.

The comparisons indicate that the 1D method provides a good or modestly conservative prediction of the 3D relative stability ratios for these similar generator models. Note, in particular, that the 1D method essentially bounds the maximum 3D ratios observed for each tube row. This is so for the smaller radius tubes which, based on past experience, are typically the tube rows of interest in the tube vibration/fatigue evaluations. The variation in ratios for the plants within each steam generator model reflects differences in the basic thermal/hydraulic operating conditions (Wsteam, Psteam, and circ ratio). Further, this plant-to-plant variation is maintained for each of the tube rows which are plotted. The fact that the plant-to-plant variation in the 1D ratios follows the 3D trends indicates that the operating condition contribution to the relative stability ratio can be adequately accounted for by the 1D approach.

Overall, the comparison demonstrates that the 1D calculation method can provide meaningful relative stability ratios in support of tube fluidelastic vibration/fatigue assessments. In particular, the one-dimensional technique can be used to adjust tube-specific stability ratios determined from detailed three-dimensional calculations for the effects of differences in thermal/hydraulic operating conditions. This 1D-to-3D adjustment is justifiable as long as its applied within a group of steam generators which share a common tube bundle configuration, as in the case of the 27, 44, and 51 Series feedring generators. In these situations, the overall tube bundle flow fields will be similar and the individual plant ratios will differ only as a result of the effects of variations in the basic thermal/hydraulic parameters.

The downcomer flow resistance plate in the 51 Series steam generator is positioned 30 inches below the girth weld centerline. Also, the top of the wrapper (the trough region between the riser barrels) is just below the girth weld elevation. In this configuration, removal or retention of the DCRP would probably have much less effect on the potential for girth weld cracking than in the 44 Series steam generator. This is due to the expected impingement location of cold water being well below the girth weld (with or without the impingement plate) and thus the thermal discontinuity is at a different elevation (lower) than the structural discontinuity at the girth weld.

In the case of a Model 51F, the DCRP is positioned slightly above the girth weld centerline. As in the case of the 44 Series, the removal of the DCRP would be beneficial to the potential for girth weld cracking in the Model 51F, given the postulated thermal hydraulic boundary conditions. With the DCRP, the thermal and structural discontinuities are nearly coincident. Without the DCRP, they are separated.

Both of the previous evaluations have identified tubes that require preventive action to preclude a North Anna R9C51 type tube rupture (Tech Bulletin 88-02). Tubes requiring preventive action for the plant in the non-uprate condition were identified and corrective action taken in late 1987/early 1988. The evaluation to determine the effects of the uprating was performed in mid 1988 and identified 4 tubes that would require preventive action before an uprate would be recommended. These tubes appear in Table 2.6-7 (3A) and were determined assuming a 'plug and stabilize'approach would be used. As can be observed in the table, one of the tubes has been previously plugged, R11C46. If this tube is not stabilized, than an additional 8 tubes would require plugging (with sentinel plugs) to 'Box in' the effected tube, Table 2.6-7 (3B).

The tubes previously identified in the non-uprate and uprate evaluations have received preventive action in the form of installing sentinel plugs or cable stabilizers. Table 2.6-8 is presented that contains a summary of the five worst case but acceptable tubes that remain after the previously transmitted preventive actions have been completed. These tubes have been evaluated in the current DCRP removal evaluation to determine if any additional actions would be required (see Figures 2.6-4 and 2.6-5). As can be observed in Table 2.6-8, the most limiting tube of the five is the R10C62 tube located in SG 21. With the steam generators operating in the uprated condition and the DCRP removed, it has been determined that this tube has a stress ratio of 0.99. Acceptability, subject to confirmation of fatigue usage less than 1.00, is determined by demonstrating that the stress ratio is less than or equal to 1.00. This tube meets this criteria along with all the remaining tubes in the table.

Finally, a summary of the fatigue usage calculation for the 'worst case but acceptable' R10C62 tube located in SG-21 is presented in Table 2.6-9. Fatigue usage has been calculated for both 30 years and 40 years of total operation. The current usage accumulated to date has been added to the projected usage that would result in either 30 or 40 years of total operation. Note that the current usage accumulated to date is 0.00. Essentially no usage has been accumulated due to the relatively benign conditions associated with the unit in the non-uprated with DCRP condition and the relatively short time of operation at higher power levels. These three factors (non-uprate, DCRP installed and length of operation) result in no substantial fatigue usage accumulating. As can be observed in the table, the usage factor is less than 1.00 for both 30 years and 40 years of operation. This demonstrates that no additional tubes will require preventive action to preclude a North Anna R9C51 type tube burst due to removal of the DCRP.

2.6.2 <u>Recommendations For Mitigation</u>

Based on fatigue usage calculations for the four groove models, it is concluded that 1) removal of the downcomer flow resistance plates will provide about a factor of three improvement in fatigue usage and 2) restoring the groove depth to about 1.0 inch would provide an additional improvement (Table 2.6-10).

Since the maximum groove depth that will remain in service is approximately 1.0 inch or less, the stress intensity evaluation of WCAP-11730 is still appropriate and shows that the stress limits are satisfied.

SG Reci:culation Flow Path

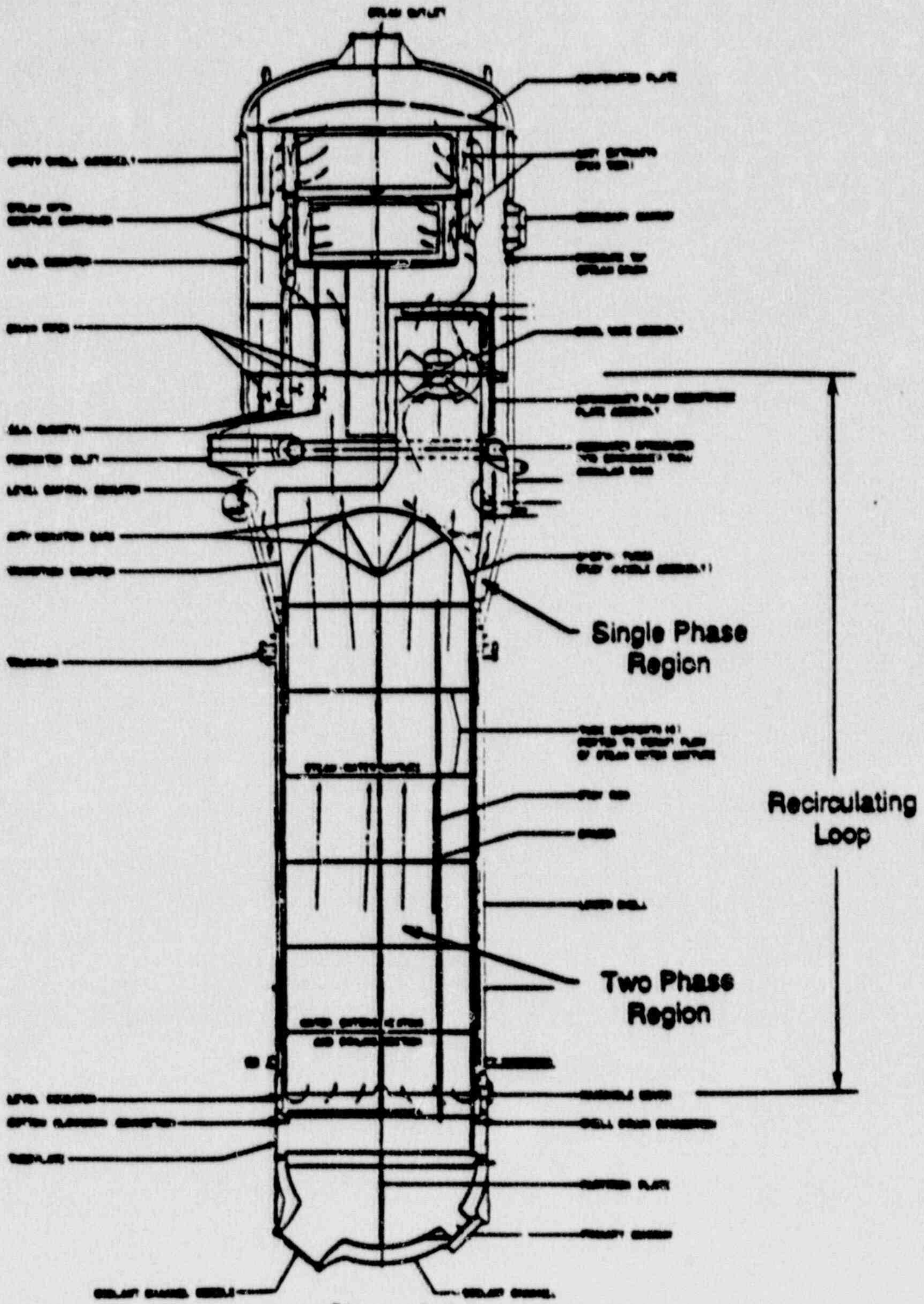
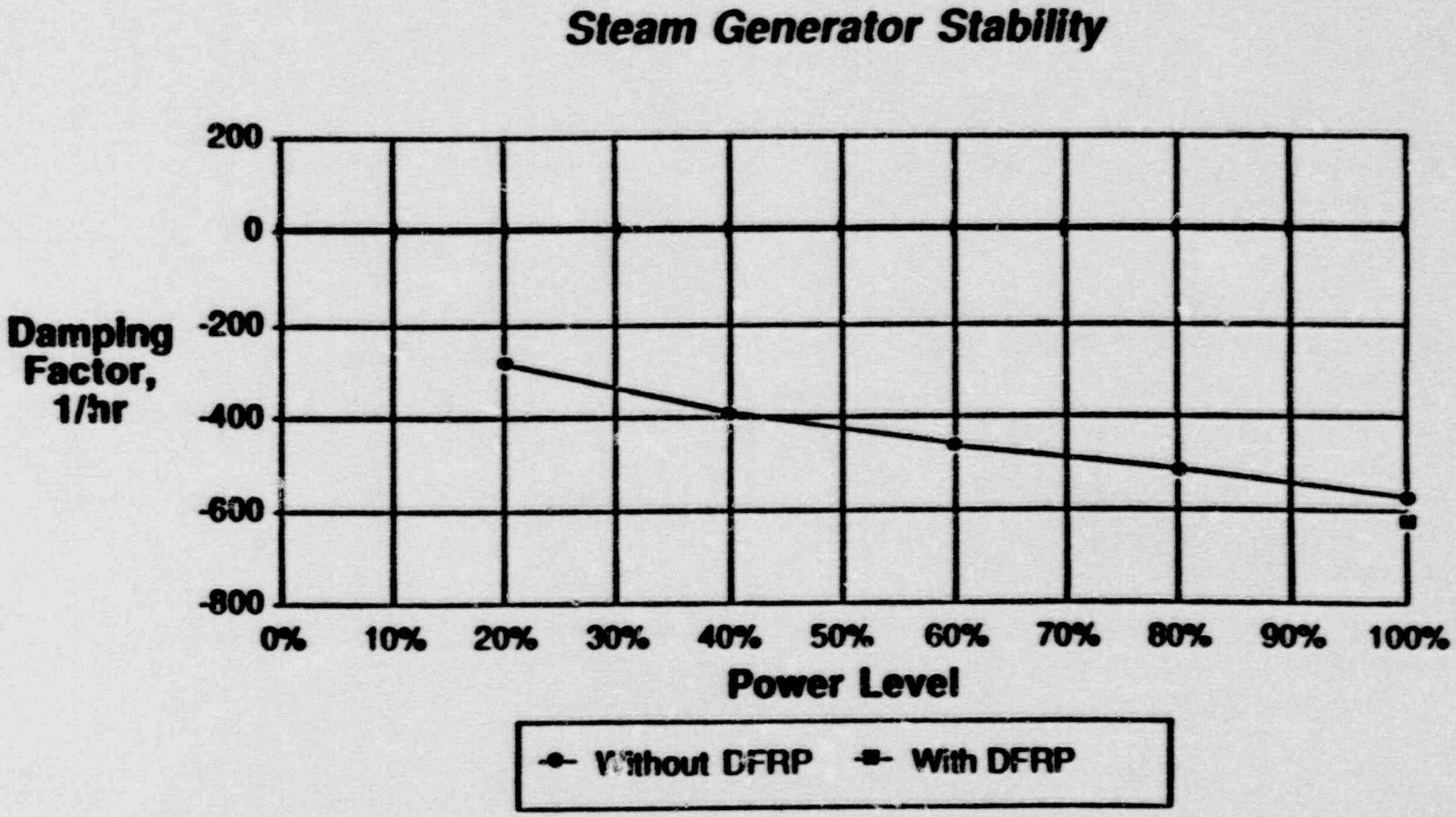


Figure 2.6-1



Steam Generator Stability
200
0
-200
-400
-600
-800
Damping Factor, 1/hr
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Power Level
Without DFRP
With DFRP

Figure 2.6-2

a,c

Figure 2.6-3 Comparison of Relative Stability Ratios
Calculated From 1D and 3D Methods

a,c

Figure 2.6-4 Relative Stability Ratio Including Flow Peaking

a,c

Figure 2.6-5 Stress Ratio Including Flow Peaking

DOWNCOMER PLATE HISTORY

Original Purpose

History of Removal

Relevance to Girth Weld Cracking

Table 2.6-1

Downcomer Flow Resistance Plates

- Hydrodynamic instability can produce water level fluctuations in recirculating steam generators.
- Stability is a function of the relative sizes of the single phase and two-phase pressure drops in the recirculation loop.
- An increase in single phase pressure drop is stabilizing.
- An increase in two-phase pressure drop moves a stable SG closer to the point of instability.
- Downcomer flow resistance plates produce single phase pressure drop.
- In the late 1970s DFRPs were removed from most SGs to increase tube bundle flow - to reduce the size of the tubesheet sludge piles.
- DGRPs were removed from the Indian Point 3 SGs over 9 years ago.
- No Westinghouse 44 Series or 51 Series SG has ever exhibited unstable operating characteristics - with or without DFRPs.

Table 2.6-2

HYDRODYNAMIC STABILITY WITH & WITHOUT DCR PLATE

PLANT	DCRP	POWER (%)	DAMPING FACTOR (1/HR)
Plant X	No	100	-192
IPP	Yes	100	-580
	No	100	-505
	No	80	-502
	No	60	-482
	No	40	-436
	No	20	-342

Note: The more negative the damping factor the more stable the SG.

Table 2.6-3

Listing of Units Where Downcomer Flow Resistance Plates have been Removed

(1976 - 1980 partial listing)

[9]

Table 2.6-4

DOWNCOMER FLOW RESISTANCE PLATES

Relevance to Girth Weld Cracking

- Many plants have removed DCFR plates and have not had cracking

- [ ] [g] has removed DCFR plates and have not had a reccurence of cracking

- [ ] [g] removed DCFR plates prior to finding girth weld cracking

Table 2.6-5

	'Current' Design Conditions	'Uprate' Design Conditions
Power Level	100	111.8
Thermal Power - MWt	694	770.8
Primary Flowrate - GPM	89,700	80
Primary Inlet Temp. - F°	579	591.4
Primary Outlet Temp. - F°	525	525.3
Feedwater Flowrate - lbm/hr	2.93×10^6	3.31×10^6
Feedwater Temp. - F°	416	430
Bundle Steam Pressure psia	700(-)	650
Outlet Nozzle Steam Pressure psia	690	641
Circulation Ratio		
Water Level (narrow range span)	40-45%	42.5%

a,c

Table 2.6-6

Indian Point Unit 2
Steam Generator Operating Conditions
Used as Input for ATHOS Analysis

Table 3A

Tubes Effected if 'Plug and Stabilize' Approach is Used

Steam Generator	Tube (Row/Column)
21	None
22	None
23	None
24	R9C65 R10C71 R11C45 R11C46 *

Table 3B

Additional Tubes Effected if 'Box Plugging' Approach is Used

24	R9C65 R10C71 R11C45 R11C46 * ** R12C45 ** R12C46 ** R12C47 ** R11C47 ** R10C45 ** R10C47 ** R9C45 ** R9C46

* This Tube Previously Plugged
** 'Box Plugged' Tube

Table 2.6-7

IPP - CRITICAL TUBES WITH RESPECT TO UBEND FATIGUE

S/G	TUBE LOCATION	PRE-UPRATE		UPRATED		UPRATE NO DCRP	
		REL STAB RATIO	STRESS RATIO	REL STAB RATIO	STRESS RATIO	REL STAB RATIO	STRESS RATIO
21	R10C62	0.67	0.17	0.89	0.92	0.90	0.99
	R11C03	0.77	0.23	0.86	0.74	0.89	0.80
22	R11C37	0.67	0.15	0.89	0.80	0.90	0.86
23	R11C47	0.79	0.40	0.88	0.75	0.91	0.92
24	R11C51	0.68	0.16	0.89	0.82	0.90	0.88

Table 2.6-8

CALCULATION OF FATIGUE USAGE - IPP/21
TUBE LOCATION R10C62

Input values for the ANALYZED cycle (from OPEVALM output):
  Tube Frequency, W Hz 60.5
  Relative SR with Peaking, SRR2*RFLOWP ... 0.897
  Stress Ratio, C2WD 0.99
    Multiplier A is Calculated............: 2.410
Input NA (SA)max for computing tube SA 9.5

Note: First row below MUST BE the Reference OPERATING Cycle.

(1) CYC	(2) NORM. RSR	(3) TUBE RSR	(4) TUBE SR	(5) TUBE SA	(6) TUBE SM	DAYS	CYCLES n	(7) ALLOW. N	USAGE n/N
A	1	0.897	0.99	3.92	50.88	365	1.9E+09	7.1E+10	0.026

					PREVIOUS USAGE
0.60	=	30 Year Basis =	0.60	+	0.00
0.87	=	40 Year Basis =	0.87	+	0.00

----
* Next Cycle = 01 YRS of operation assumed at 100% availability with Ref. OPERATING Cycle parameters (in Row #1).

(1): A, B, and C refer to 100%, 95%, and 90% power levels.
(2): RSR Normalized wrt the ANALYZED Cycle.
(3): Calculated using normalized RSR*Ref. Analysis RSR.
(4): A*C2WD*(RSR+.062)^6 IF RSR<.938; A*C2WD*RSR^10, Otherwise.
(5): SA=.41468*(SA)max*SR*SBAR/SBARP = .568*(SA)max*SR/W^.0755
(6): SM=54.8-SA, i.e., assume max effect of mean stress.
(7): Calculated with S-N-T with -3*sigma formulation (NAFAT2).

Table 2.6-9

FATIGUE USAGE EVALUATIONS

Recommendations For Mitigation

Remove Downcomer Plate

Restore Groove Depth to About 1.0 Inch

Table 2.6-10

2.7 Fracture Mechanics

2.7.1 Fracture Mechanics Evaluation

Tables 2.7-1 to 2.7-11 and Figures 2.7-1 to 2.7-7 are copies of material presented to the NRC at the May 11, 1989 Con Ed meeting.

The fracture mechanics evaluation of the girth weld was carried out to determine the critical flaw depth for flaws postulated in this region and to determine the sensitivity of these regions to fatigue crack growth. In addition, a sensitivity evaluation was carried out which shows that leak-before-break can be demonstrated for the girth weld region and further shows that very large flaws are required in this region to produce a failure.

1) Critical Flaw Depth

The steam generator upper shell to cone region is made of SA302B steel. The fracture toughness used in the evaluation was the KIR curve of the ASME Code. The toughness used was 200 ksi root in. The governing transient for this region of the steam generator is the reactor trip and the lowest metal temperature which could exist during a reactor trip was found to be 250°F.

The fracture toughness procedure from the ASME Code curve requires the determination of RTNDT. The RTNDT levels obtained for the base material are taken from material test certifications and the USNRC standard review plan was used to determine that RTNDT = 10°F. A similar procedure was used for the weld material. Weld qualification test records were obtained for this region, and RTNDT was found to range from 10 - 30°F. The RTNDT for the heat affected zone was obtained from the Gleeble testing reported earlier and determined to be -20°F; therefore the governing RTNDT for this region is 30°F. Since the lowest metal temperature is 260°F during the transient, the girth weld material will always be on the upper shelf of fracture toughness (Figures 2.7-1 and 2.7-2).

The stress intensity factor was calculated for a range of postulated flaws in this region and results are shown in the figure for the reactor trip transient [ ]^{a,c} (Figure 2.7-3). This figure shows the critical flaw depth for any of the postulated flaws exceeds 25% of the remaining wall. This figure was obtained from the analysis of the 1 inch deep grinding configuration with the downcomer resistance plate removed.

2) Fatigue Crack Growth

Fatigue crack growth analyses were carried out for indications postulated to exist in this region including 4 different grinding depths from 1/2" to 1.25" deep. The stresses used in the analysis were taken directly from the fatigue analysis report discussed earlier and included the full duty cycle of design transients. The Section XI water environment fatigue crack growth reference curves were used in the analysis. The results are shown in the Figures 2.7-4 to 2.7-7. For a postulated initial crack depth of .02", (similar to the pitting depth) the fatigue crack growth was found to be very dependent on the grinding configuration. Results are reported for a three year operating period and show for the .75 and 1.0" grinding depths that over .2" of crack extension is predicted. The average crack extension in the grind regions of the girth weld was found to be .25". The fatigue crack growth results are therefore consistent with experience during the past cycle.

The modelling of the grinding configurations for 0.5 and 1.25" included a rounded groove and therefore were less severe than those for the .75 and 1" grind and the crack growth was therefore lower. In all the crack growth analyses performed, the cross section chosen was the highest stressed location within the entire grind-out region. The transient which made the largest contribution to fatigue crack growth in all four cases was [

]^{a,c}

3) Leak-Before-Break-Safety Assessment

In this section, analysis results will be presented to show that a crack would grow to a through-wall configuration and produce a leak well before the flaw would become unstable. The crack morphology of the observed cracks in the girth weld region were evaluated to determine the length of a through-wall flaw which could cause instability.

The cracks observed in the girth weld region in all of the instances to date have been of uneven depths. This promotes a local penetration of the wall, if it were to occur. The mechanism of crack penetration has been shown to be corrosion fatigue. The material toughness is quite high as shown by the material properties discussed above. Ductile fracture would be expected to occur in this region both due to high toughness and the high temperature. Furthermore, experience supports that a leak-before-break was observed in another steam generator due to flaws in this region.

The calculation of the instability flaw length in the girth weld region was done using the governing transient, the reactor trip. The stress intensity factor was calculated from the expression below:

$$[\qquad\qquad\qquad]^{a,c}$$

where sigma = the applied stress. a = the flaw half length.

The fracture toughness was determined to be 200 ksi root inch, since the vessel material was found to be on the upper shelf of the KIR curve. Results of the assessment for all four grind depths showed the critical length for a through wall flaw calculation using LEFM was in excess of 7".

Ductile fracture analyses were are also completed for the girth weld region including all four grind geometries (from .5" to 1.25"). The critical length was found in all cases to exceed 175" or 34% of the circumference. This is expected to be a more realistic prediction of the true critical length for a through wall flaw in this region. Clearly measurable leakage will occur before the critical length is reached. A measurable leakage rate of 5 gpm within containment requires containment entry for identification of leakage source. A 5 gpm leak rate could occur for a crack length of [ ]^{a,c}

The consequences of a through-wall crack postulated in this region has been evaluated. From the analyses reported above, no failure would be expected. Leakage would occur but no forces would be generated from such a leak so no assymetric loads are to be expected. There will be no impact of such a postulated leakage on the primary side pressure boundary because the girth weld is widely separated from the primary side.

2.7.2 Fracture Analysis For Demonstration of Margin In Girth Weld Region

Each of the steam generators requires analysis of adequate margin for continued operation.

The allowable fracture toughness was taken as the actual fracture toughness divided by the square root of 2. This resulted in an allowable toughness of 200 divided by the square root of 2 = 144 ksi square root in.

For each of the steam generators the applied stress intensity factor was calculated for each of the grind out areas, starting with the greatest depth. At each grind out area, a crack was postulated with the depth equal to the maximum extension during the past cycle, and the driving force, or stress intensity factor for a surface flaw with aspect ratio 20:1 was calculated. This stress intensity factor was compared to the allowable toughness of 144 ksi square root in. The goal was to determine the number of grinds which do not meet this criterion.

In making the calculation of the stress intensity factor, appropriate transient stresses were used. The residual stress for this region are considered to be negligible.

The calculation was carried out for each of the grinding depths analyzed, ranging from 0.5 to 1.00 inch. The 1.25 inch grind was not needed, since all grinds will be removed to a depth of approximately 1.0 inch or less.

The results of the stress intensity factor calculation for the three cases is provided in the Figures 2.7-8 to 2.7-10. The analyses used here were for the governing transient, the reactor trip, for the highest stress time step. It was assumed that the downcomer resistance plates were removed. The three figures have on them the allowable fracture toughness, along with stress intensity factors for three different flaw shapes. The flaw shapes range from an aspect ratio of 6:1 to a very long flaw for which length is 100 times the depth.

From these figures we find the deepest flaw allowed in any of the generators:

	Allowed Crack
0.5 inch grind	> 1 inch
0.75 inch grind	0.96 inch
1.00 inch grind	0.95 inch

Considering the amounts of crack extension experienced in the steam generators during the last cycle, we have the following maximum values:

	Maximum Depth
S/G 21	0.30
22	0.95
23	0.33
24	0.34

Therefore we see that the maximum depth of cracking in any given generator, if postulated to exist at any grinding depth, will meet these criteria to assure that the requested margin is demonstrated.

a,c

Charpy Results and RTNDT Determination

Figure 2.7-1

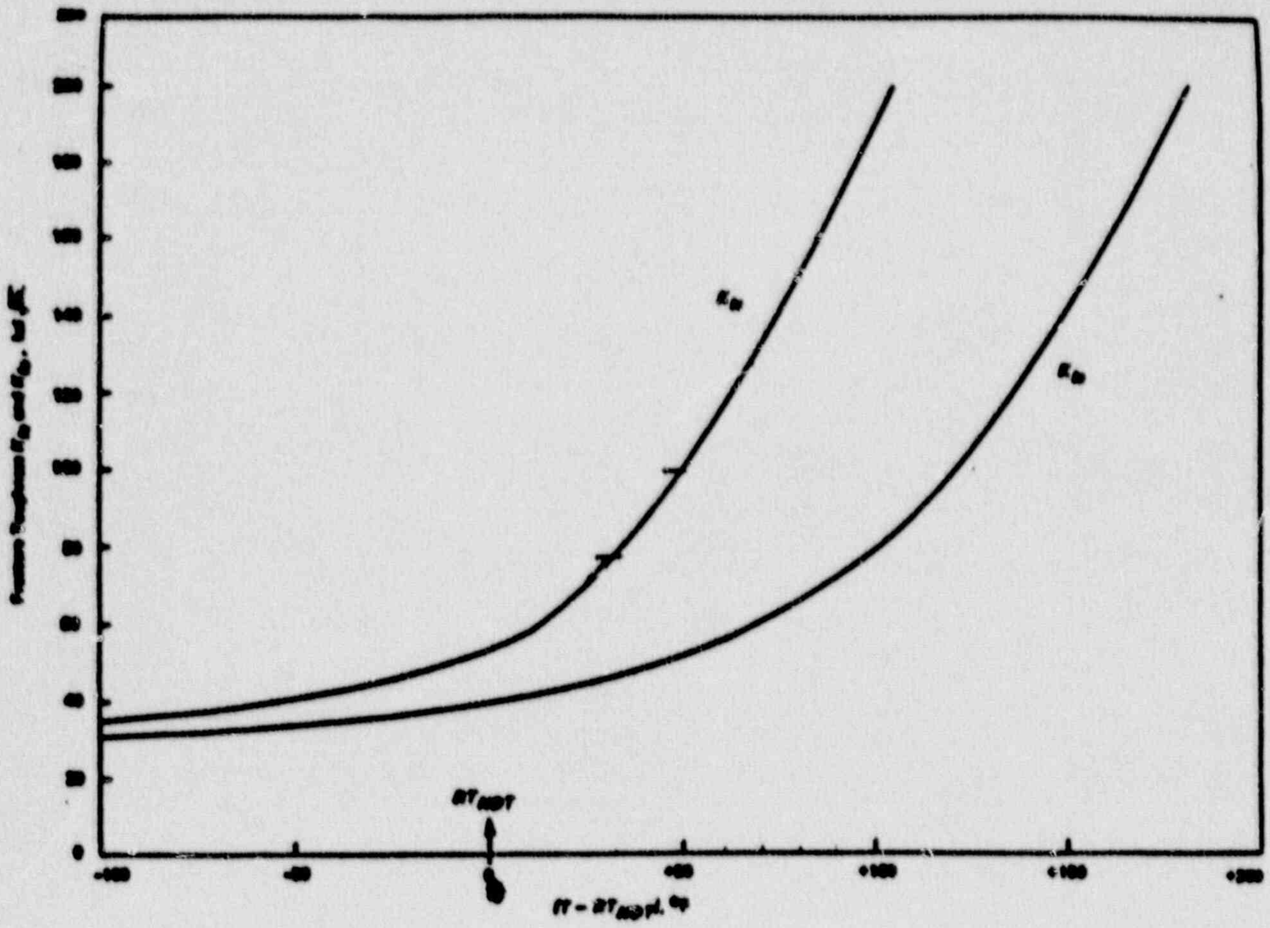


Figure 2.7-2

Reference Fracture Toughness Curves

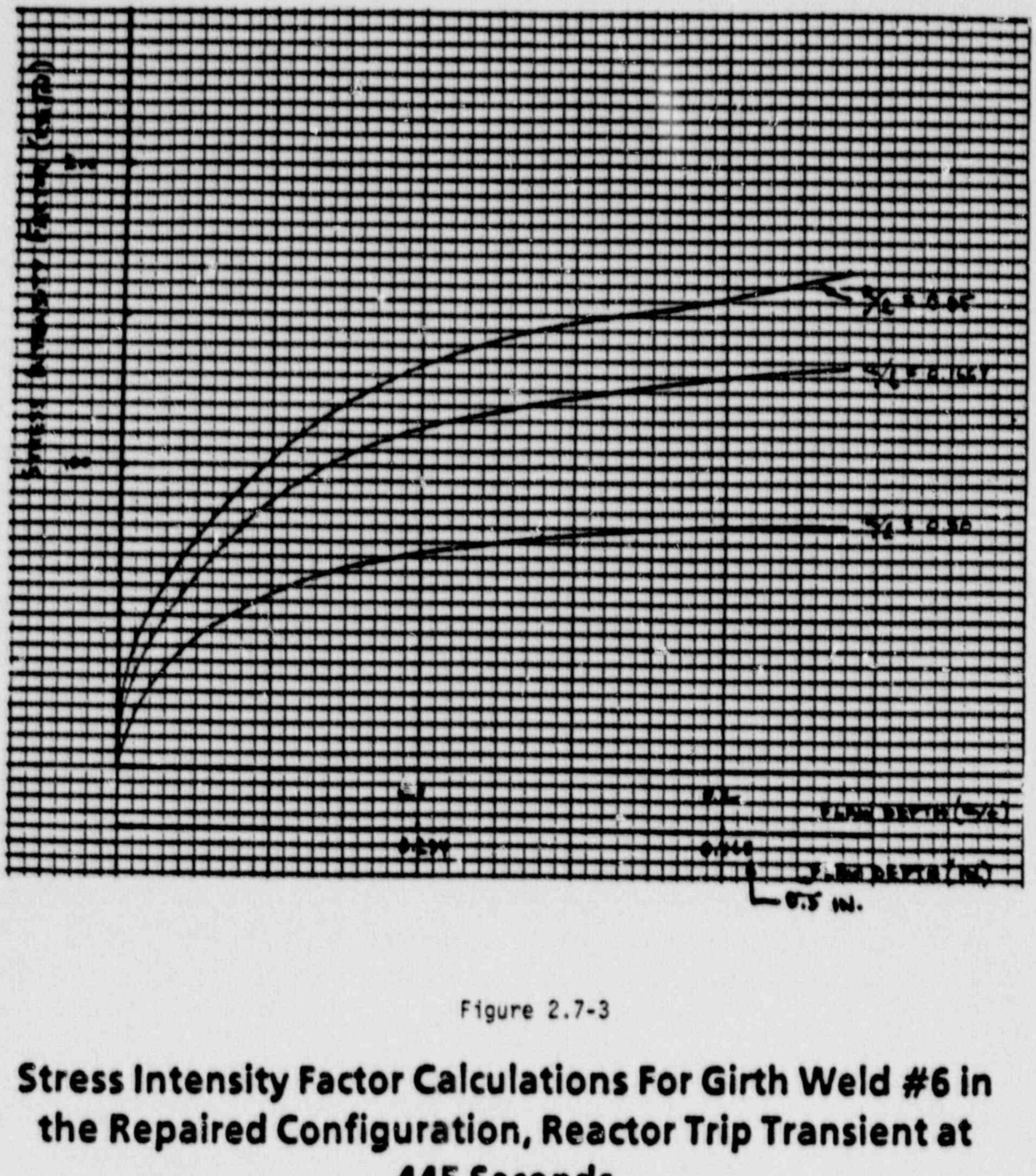
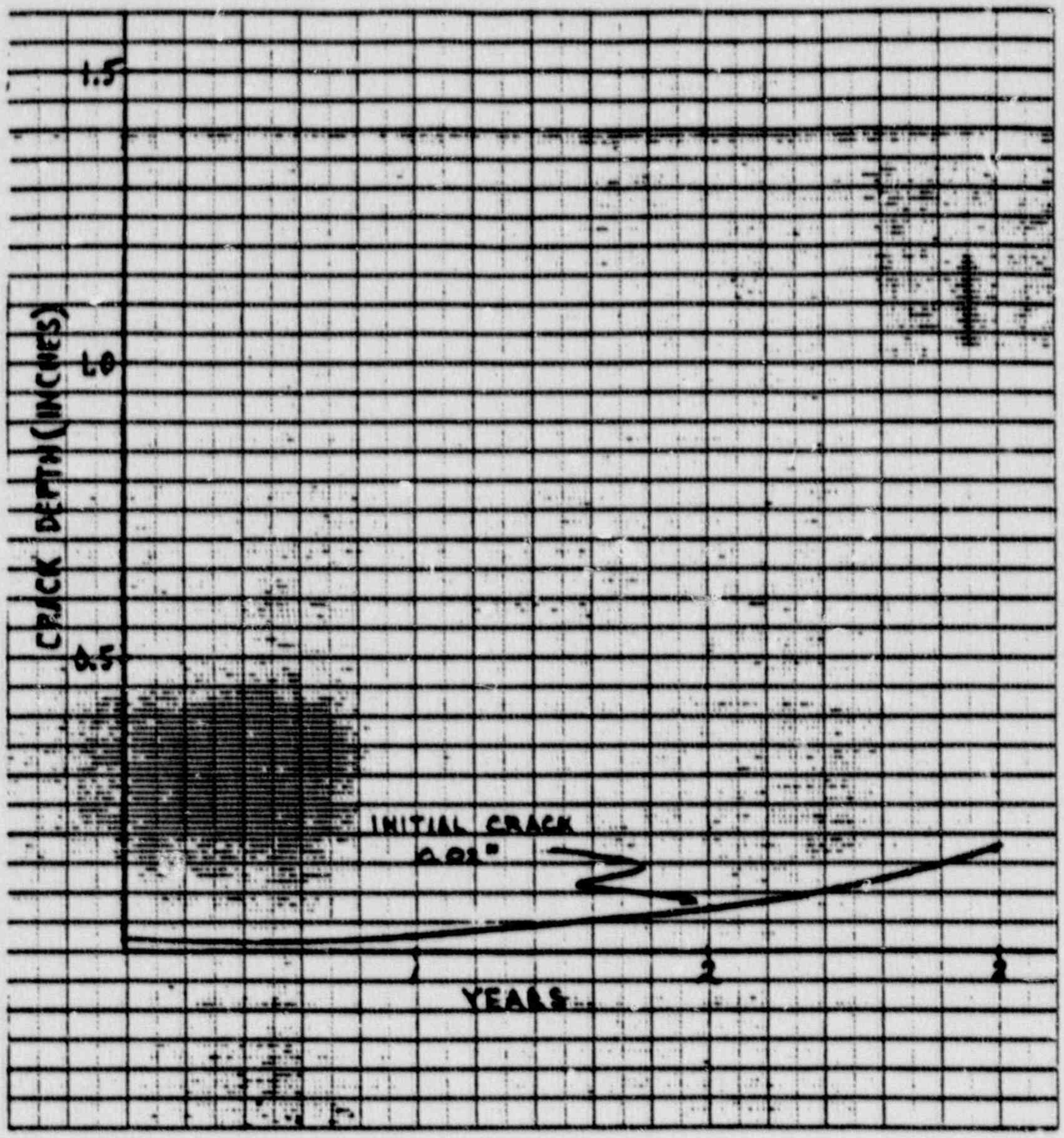


Figure 2.7-3

Stress Intensity Factor Calculations For Girth Weld #6 in the Repaired Configuration, Reactor Trip Transient at 445 Seconds



Fatigue Crack Growth Results: 0.50 Inch Grind

Figure 2.7-4

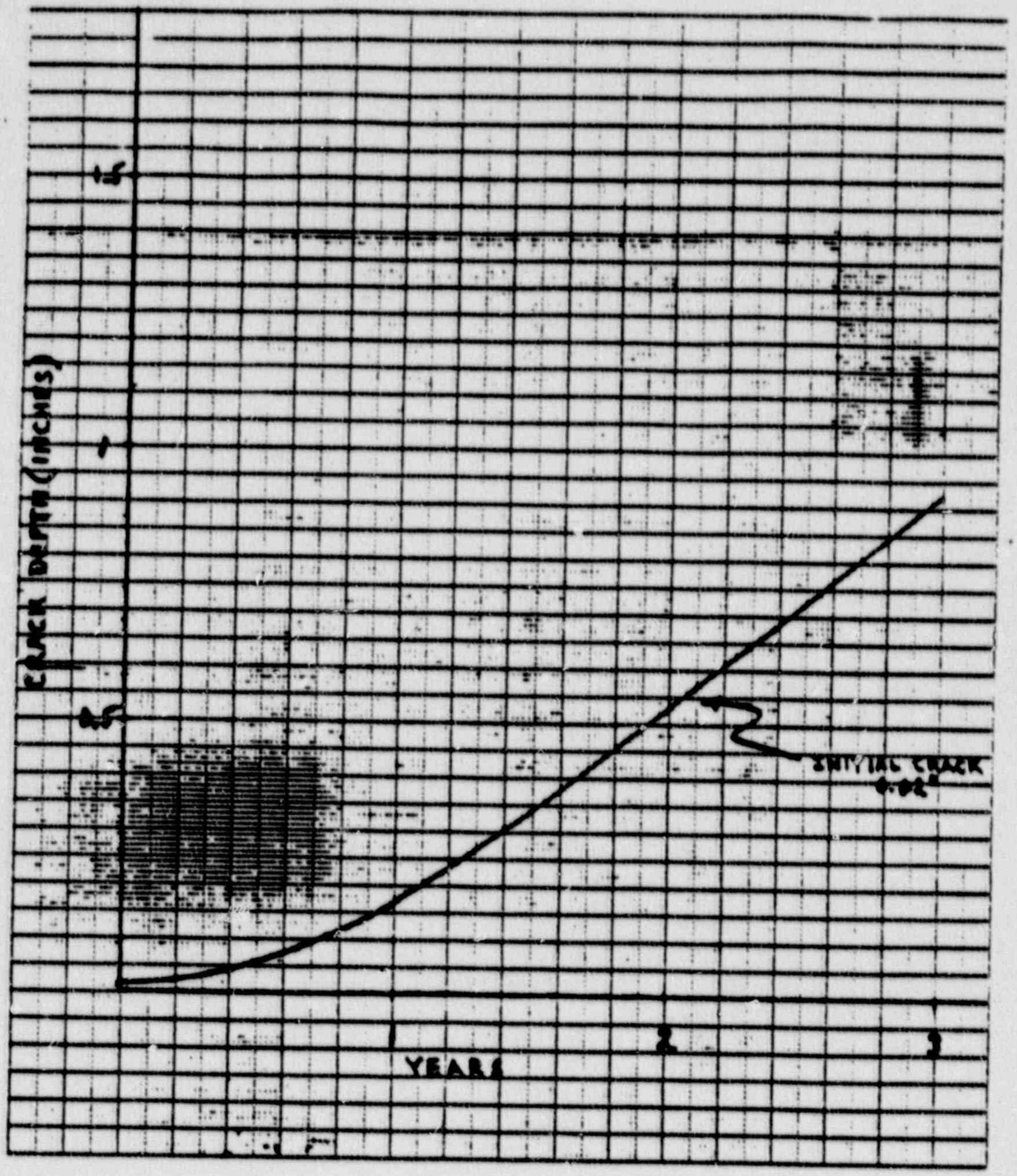


Figure 2.7-5

Fatigue Crack Growth Rate Results: 0.75 Inch Grind

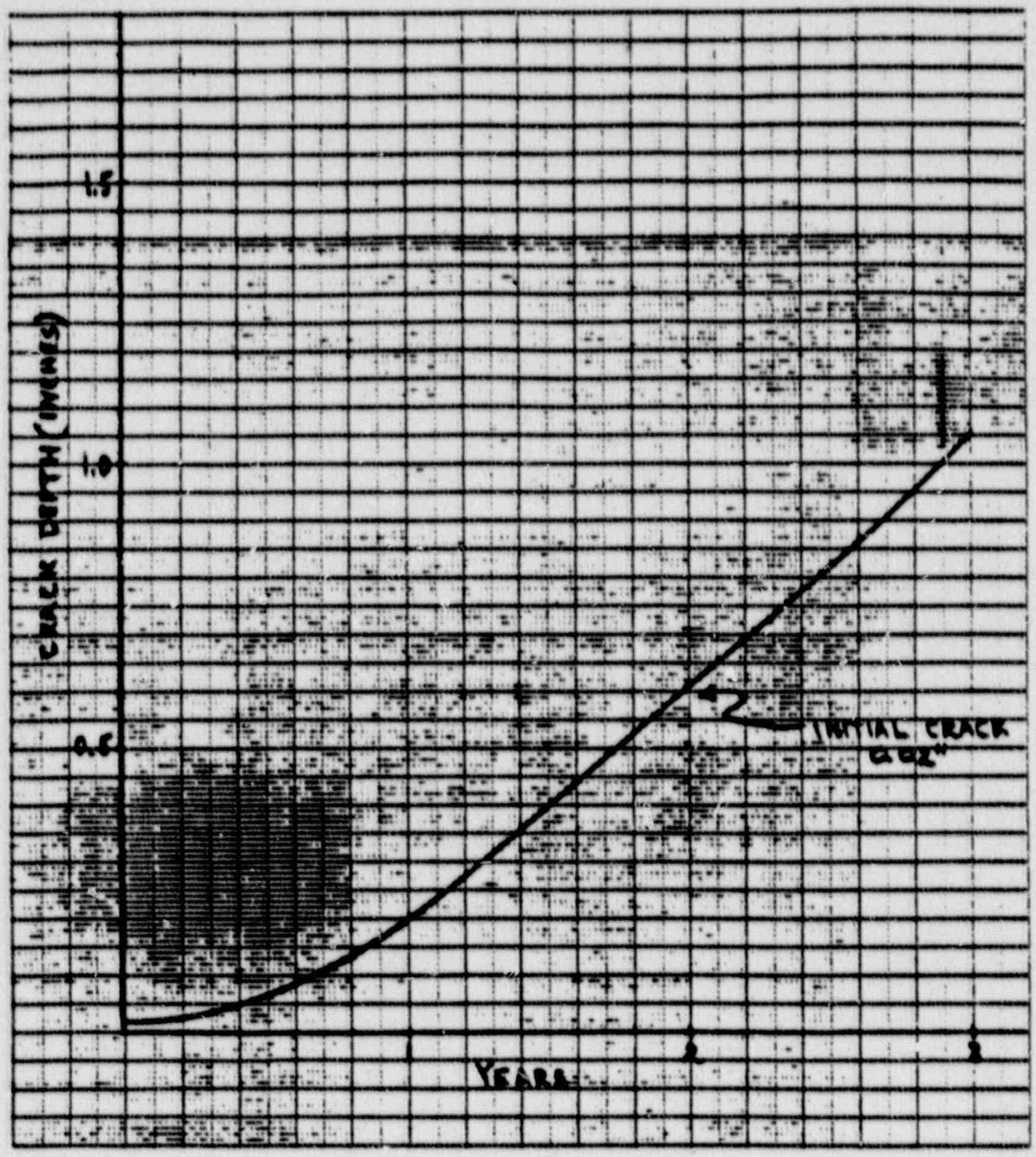


Figure 2.7-6

Fatigue Crack Growth Results: 1.0 Inch Grind

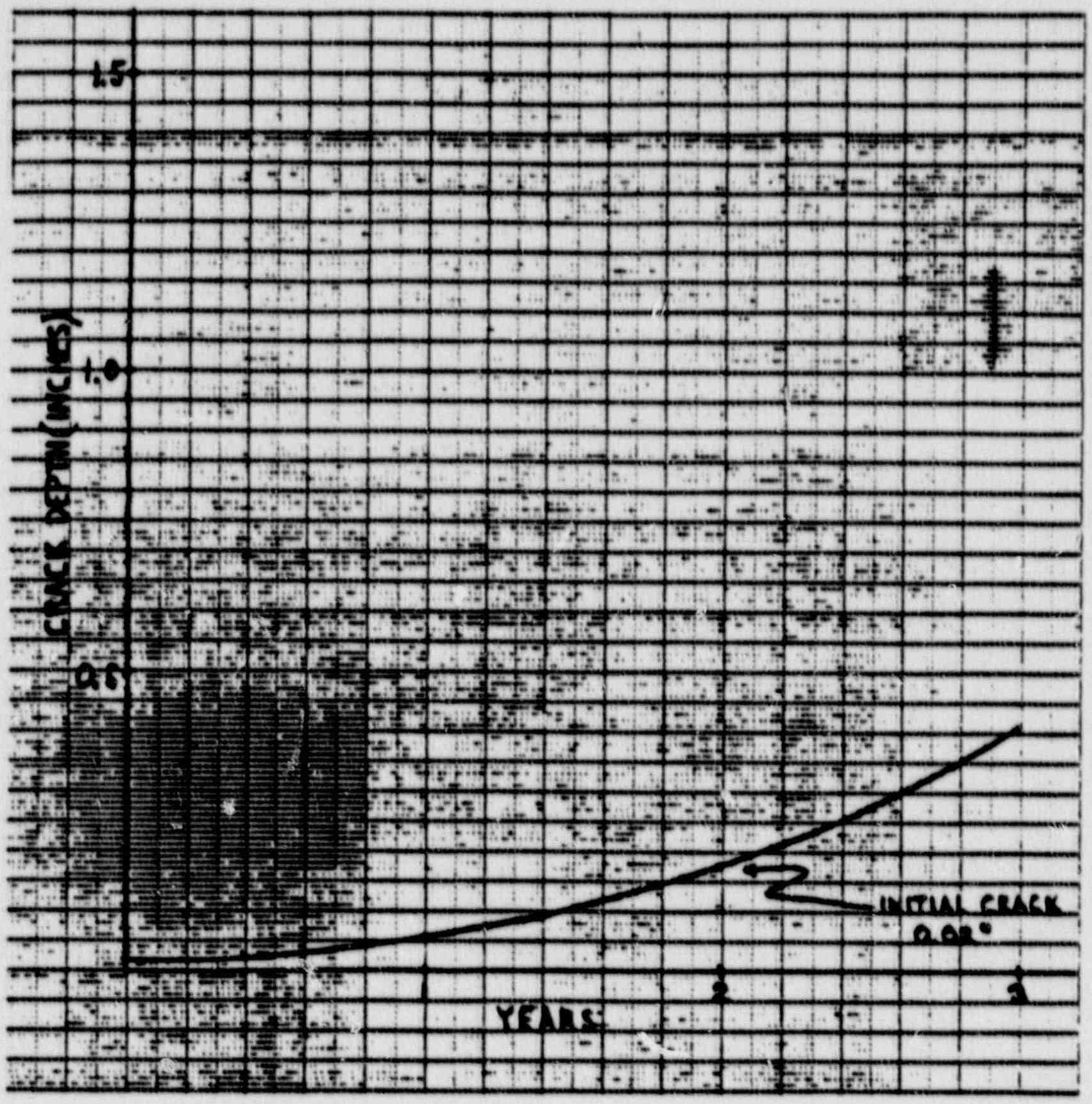


Figure 2.7-7

Fatigue Crack Growth Results: 1.25 Inch Grind

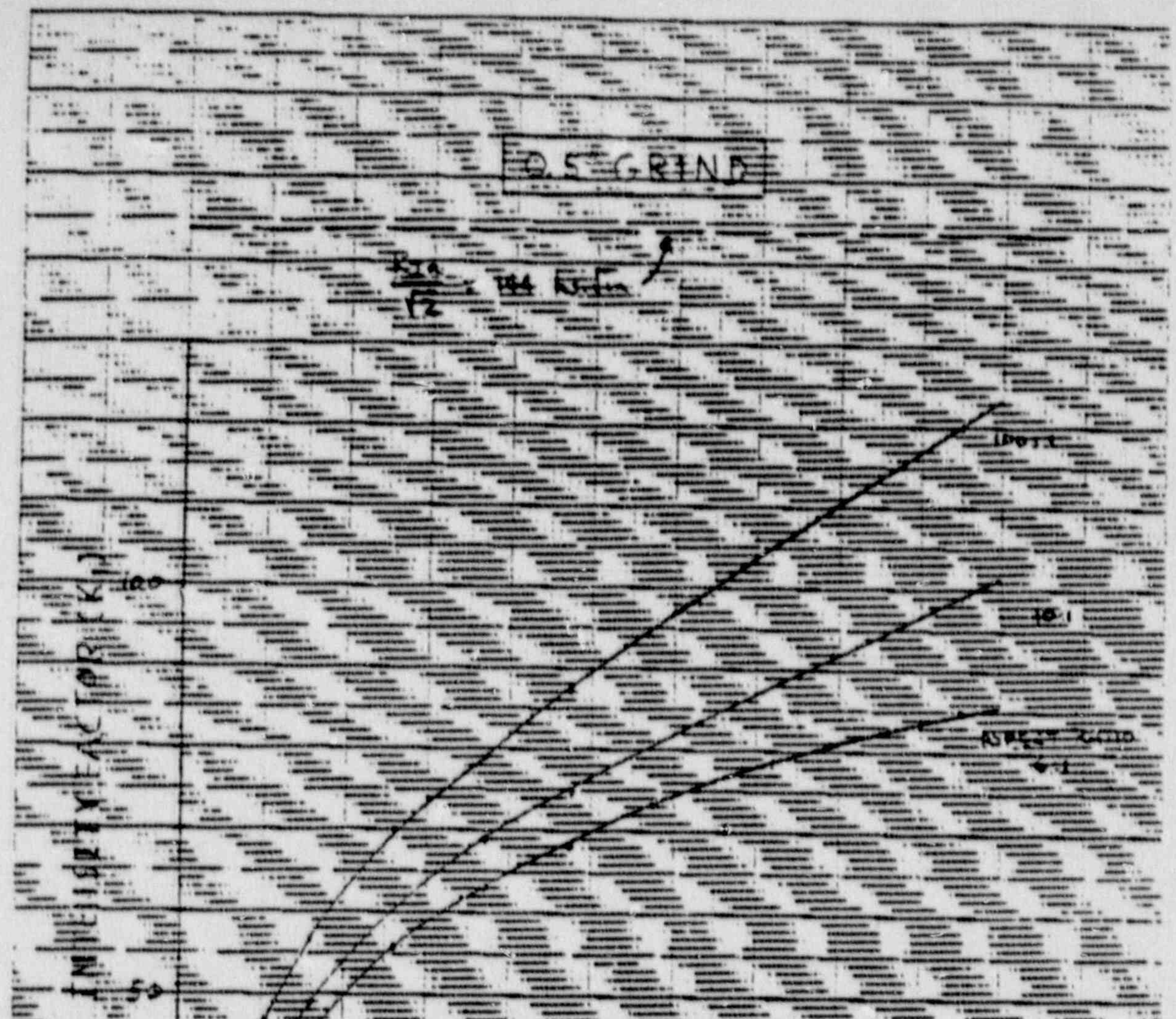
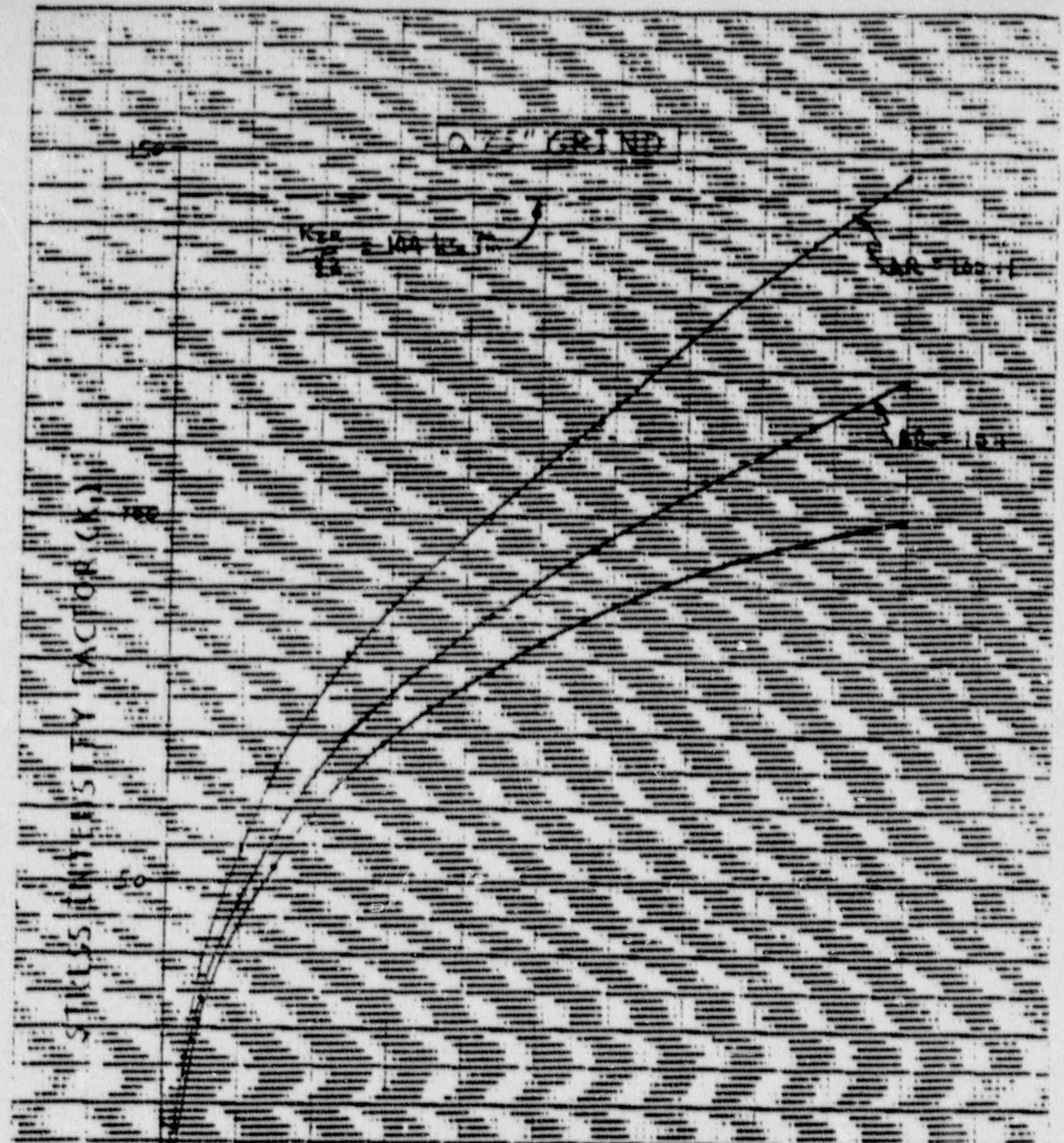
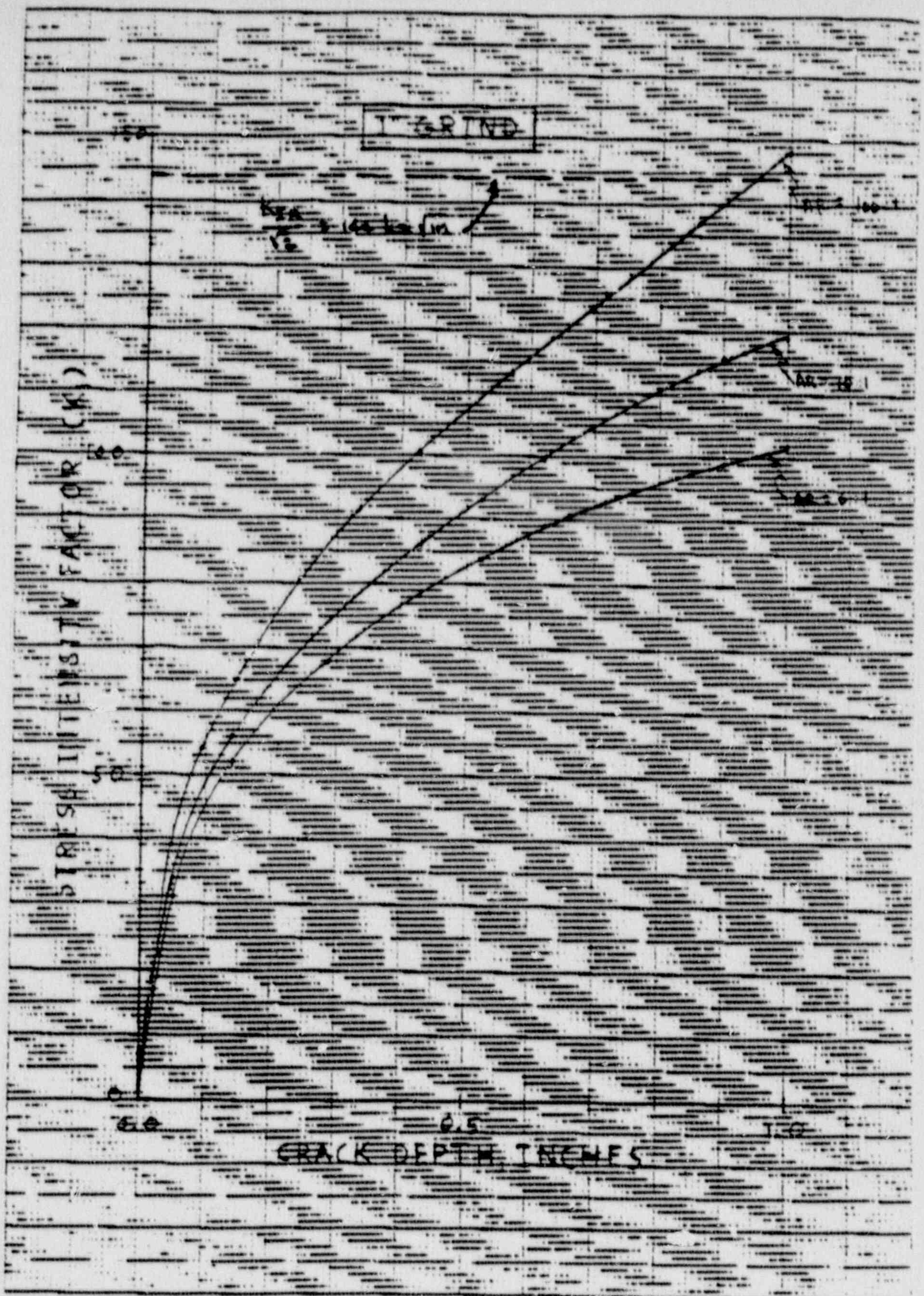


Figure 2.7-8



0.75" GRIND
150
100
50
0.0
STRESS INTENSITY FACTOR (K_I)
CRACK DEPTH, INCHES

Figure 2.7-9



STRESS INTENSITY FACTOR (K)
150
100
50
0
0.0
0.5
1.0
CRACK DEPTH INCHES

Figure 2.7-10

G. FRACTURE MECHANICS EVALUATIONS - GIRTH WELD

- Allowable Crack Depth
- Fatigue Crack Growth Results
- Leak Before Break
- Consequences of a Through Wall Crack
- Recommendations

Table 2.7-1

ALLOWABLE CRACK DEPTH

Material: A302B

Fracture Toughness:	**Use K_{IR} Curve** **Upper Shelf Toughness:** **200 Ksi$\sqrt{in}$**
Governing Transient:	**Reactor Trip** **Lowest Temperature: 260°F**
Critical Flaw Depth:	**Exceeds 25 Percent of Thickness**

Table 2.7-2

RT_{NDT} DETERMINATION

Base Metal (From Matl. Test Cert.)	**10°F**
Weld Metal (Weld Qualification Tests)	**10-30°F**
HAZ (From Gleeble Testing)	**-32°F**

Table 2.7-3

FATIGUE CRACK GROWTH

- Stresses Taken From Fatigue Analysis - Full Duty Cycle Per Design Requirements
- Used ASME Section XI Water Environment Curves
- Considered Several Grind-Out Geometries

Table 2.7-4

Major Contribution To Crack Growth:

Feedwater Cycling At Hot Standby

Table 2.7-5

LEAK BEFORE BREAK

Issue: **Will a Crack Grow to a Through-Wall Configuration and Produce a Measureable Leak Before Instability:**

- **Crack Growth Morphology**
- **Instability Flaw Length Calculation**
- **Experience**
- **Results**

Table 2.7-6

CRACK GROWTH MORPHOLOGY

- Crack Depths Are Uneven - Promotes Penetration Locally

- Mechanism of Crack Penetration is Corrosion-Fatigue, A Slow Steady Process

- Material Toughness is Quite High, Ductile Fracture Would Be Expected Due To High Temperature

- Field Experience Supports Leak Before Break

Table 2.7-7

INSTABILITY FLAW LENGTH CALCULATION

- Governing Transient: Reactor Trip
- $K = \sigma\sqrt{a\pi}$ $(\sigma = \sigma_m + 0.5\sigma_b)$
- Fracture Toughness = 200 ksi$\sqrt{in}$
- Results

  Critical Length = 7 inches
- Clearly Measurable Leakage Will Occur Long Before Critical Length Is Reached

Table 2.7-8

DUCTILE FAILURE PREDICTIONS - GIRTH WELD

Geometry	Critical Length	Percent Of Circumference
0.5 Inch Grind	185 in.	36
.75 Inch Grind	185	36
1.0 Inch Grind	185	36
1.25 Inch Grind	175	34

Table 2.7-9

CONSEQUENCES OF A THROUGH-WALL CRACK

- **Leakage Occurs**
- **No Forces Are Generated, So No Asymmetric Loads**
- **No Impact On The Primary Pressure Boundary**

Table 2.7-10

RECOMMENDATIONS

GRIND OUT INDICATIONS

FEEDWATER CONTROL

Table 2.7-11

2.8 Stress Relief Process

2.8.1 Assessment of Need

The primary purpose of current heat treatment is to relieve the residual stresses introduced during the new weld repair for SG 22. Reduction of residual stress (the objective of stress relief) is a secondary influence in reducing the potential for pitting and initiating new cracks. However, the heat treatment records for the girth welds were reviewed in 1987 and found to demonstrate that the welds in all four steam generators were stress relieved with a post weld heat treatment (PWHT) comparable to the heat treatment currently under consideration. Consequently, heat treatment may not reduce residual stresses below levels existing in prior operation (Table 2.8-1).

2.8.2 Potential Benefits

The beneficial effect of a thermal stress relief heat treatment is primarily dependent on the temperature and time application. In general, the metal temperature has a far greater effect on the reduction of residual stresses than does the time of application. The higher the temperature below the critical temperature of the steel, the more beneficial the stress relief affects. However, the temperature can also significantly affect the mechanical properties and toughness of the steel and hence a stress relief temperature is a compromise between the beneficial effects of relieving the residual stresses and reducing the mechanical properties and material toughness.

2.8.3 Potential Difficulties and Their Resolution

The recommended process for stress relief is to heat to 1125 +/- 25 degrees F holding 1 hour per inch of material thickness, controlling temperature in a 360 degree circumferential zone that extends 2 feet below and 6 feet above girth weld. In prior Westinghouse field experience with this process with replacement steam generator installation, insulation was installed on the inner surface down to the lower shell to transition cone joint. In addition, the feedwater and steam piping were not connected in these prior applications. These aspects of the prior heat treatment applications were re-evaluated for Indian Point 2.

Due to the very high radiation fields in the steam generators at Indian Point 2, it is desirable to keep the water level up as high as possible when work is being performed inside. To avoid water soaking the insulation and having to deal with the associated problems during heating, it is considered necessary to limit the inner surface insulation to within a few inches of the girth weld on the lower side. However, to assure that the insulating blankets do not get wet, the water level must be lowered approximately 18 inches this will result in a significant increase to the radiation field (from approximately 150 mr to 1000 mr), even with the maximum amount of lead shielding in place. The reduced inner surface insulation was evaluated and found to lead to acceptable stress levels in conjunction with specified, heater controlled outer surface temperature gradients.

By not disconnecting the feedwater and steam piping, concerns arise over the potential effect of the high temperature to cause permanent deformation of the feedwater nozzle and/or the piping. Results from material creep tests performed to evaluate the potential deformation indicate that the feedwater nozzles should not be significantly effected if the piping were not disconnected. However, the testing did show that permanent creep deformation could be expected in the piping (at the feedwater nozzle to piping joint). Since such deformation is not desirable, the feedwater pipe is to be disconnected during the stress relief. Thermal/Hydraulic and stress analysis of the main steam line piping has shown that there is minimal risk of permanent deformation at the joint of the main steam nozzle and the main steam line piping because the temperature is significantly lower at this elevation during the stress relief process (Reference Tables 2.8-2).

2.8.4 Conclusion

Considering all of the above factors post weld heat treatment will be performed for SG 22 because of the weld repairs, but no heat treatment is planned for SG 21, 23 and 24.

STRESS RELIEF CONSIDERATIONS

- BASED ON BOAT SAMPLE EVALUATIONS AND FABRICATION RECORDS, ADDITIONAL S/R OF CLOSURE WELDS WOULD SHOW MINIMAL BENEFIT

- REQUIRED ONLY IF WELD REPAIR IS IMPLEMENTED TO RESTORE GROUND AREAS (I.E., S/G 22)

- NOT REQUIRED FOR BEAD TEMPER REPAIR

Table 2.8-1

IMPLEMENTATION ISSUES

- NEED TO INSULATE ID
  - LOWER WATER LEVEL
  - HIGHER RADIATION (ALARA CONCERNS)
- PIPE CONNENTIONS
  - CUT FW PIPING

Table 2.8-2

3.0 STEAM GENERATOR FEEDWATER NOZZLE DETAILS

3.1 Inspection Results

Linear indications were found on the inner radius area of SG 22 feedwater nozzle during a scheduled visual examination in the 1989 inservice inspection program. These indications were located in approximately the lower 120 degree segment of the nozzle. Liquid penetrant examination of the steam generator 22 feedwater nozzle inner radius confirmed the existence of these linear indications and revealed additional linear indications in the fillet welded regions of two support brackets welded to the nozzle just below the inner radius. Visual and penetrant examinations of the other three steam generator feedwater nozzle inner radii revealed similar linear indications in SG 23 but no indications in SG 21 and 24.

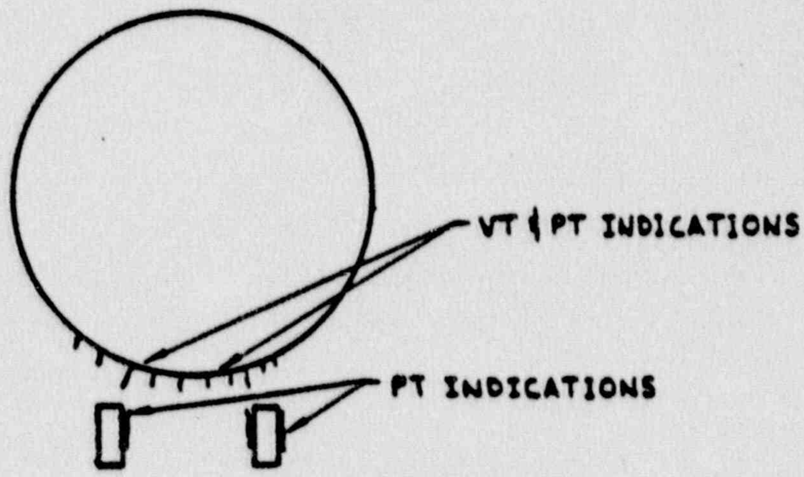
Fiberscope examinations of SG 22 and 23 nozzle thermal sleeve inner diameter surface and all four steam generators thermal liner outer diameter surface and feedwater nozzle inner bore for the lower 90 degrees resulted in no linear indications and no pitting. Ultrasonic examinations of all four steam generator feedwater nozzle bores and radiographic examinations of all four steam generator feedwater nozzle to pipe welds including the nozzle counterbore also revealed no evidence of linear indications.

Visual and penetrant examinations of the indications in the SG 22 and 23 feedwater nozzle inner radii were performed during the removal/grinding process to verify the removal of the linear indications. After grinding to depths on the order of 0.1" to 0.2", all linear indications were verified as being removed. Reference Tables 3.1-1 to 3.1-7.

INDIAN POINT UNIT 2
FEEDWATER NOZZLES

VISUAL AND PT EXAMINATIONS OF
FEEDWATER NOZZLE
REGIONS (360 DEGREES AROUND NOZZLE)

- S/G 22 & 23



TYPICAL REPRESENTATION OF LINEAR INDICATIONS

- S/G 21 & 24

  - NO LINEAR INDICATIONS OBSERVED

Table 3.1-1

INDIAN POINT UNIT 2 FEEDWATER NOZZLES VISUAL EXAMINATIONS OF THERMAL LINER I.D. & O.D. SURFACES AND NOZZLE I.D. SURFACE

FIBERSCOPE EXAMS OF S/G 22 & 23 THERMAL LINER I.D. SURFACE

- EXAMS COVERED LOWER 90 DEGREES OF THERMAL LINER
- NO CORROSION, NO SCALE AND NO LINEAR INDICATIONS OBSERVED.

FIBERSCOPE EXAMS OF ALL S/G(S) THERMAL LINER O.D. SURFACE

- EXAMS COVERED LOWER 90 DEGREES OF THERMAL LINER
- SOME SCALE, NO PITTING, NO WORMHOLES, NO LINEAR INDICATIONS OBSERVED.

FIBERSCOPE EXAMS OF ALL S/G(S) NOZZLE I.D. SURFACES

- EXAMS COVERED LOWER 90 DEGREES OF NOZZLE DOWN ENTIRE BORE, LOWER 180° ADJACENT TO INNER RADIUS
- NO PITTING OR LINEAR INDICATIONS OBSERVED WITH THE EXCEPTION OF ONE (1) EACH IN S/G 22 & S/G 23.
- INDICATION IN S/G 22 APPROXIMATELY 1 1/2" IN EXTENT FROM S/G SHELL SURFACE
- INDICATION IN S/G 23 APPROXIMATELY 1/2" IN EXTENT FROM S/G SHELL SURFACE

Table 3.1-2

INDIAN POINT UNIT 2

FEEDWATER NOZZLE

UT OF INNER BORE

a,c

[ ]

REGION 1: NOZZLE INNER RADIUS

REGION 2: NOZZLE BORE CYLINDRICAL SECTION

Table 3.1-3

INDIAN POINT UNIT 2

FEEDWATER NOZZLE

UT OF INNER BORE

REGION 1: NOZZLE INNER RADIUS

- 20°S, 2.25 MHZ, 0.5" x 1.0", CONTOURED SEARCH UNIT (APPROXIMATELY 35°S AT INNER RADIUS)

- SENSITIVITY LEVEL ESTABLISHED ON 0.1" DEEP NOTCH

- RECORDED LEVEL ESTABLISHED ON S/G 22 GRIND OUT AND CRACKS, I.E. - 26 dB BELOW SENSITIVITY LEVEL

REGION 2: NOZZLE BORE CYLINDRICAL SECTION

- 30°S, 2.25 MHZ, 0.5" x 1.0", NONCONTOURED SEARCH UNIT (APPROXIMATELY 50°S AT INNER RADIUS)

- SENSITIVITY LEVEL ESTABLISHED ON 0.1" DEEP NOTCH

- SCANNING LEVEL AT 14 dB ABOVE SENSITIVITY LEVEL (10-30% FSH I.D. SURFACE RESPONSES)

- RECORDING LEVEL: TRAVELING INDICATIONS COMING OUT OF I.D. SURFACE RESPONSES IRREGARDLESS OF AMPLITUDE

REGION 3: NOZZLE BORE TAPER SECTION

- 30°S, 2.25 MHZ, 0.5" x 1.0", NONCONTOURED SEARCH UNIT SKEWED 25° TOWARD PIPE (APPROXIMATELY 32-50°S AT I.D.)

- SENSITIVITY LEVEL, SCANNING LEVEL AND RECORDING LEVEL SAME AS REGION 2

Table 3.1-4

INDIAN POINT UNIT 2
FEEDWATER NOZZLES
UT OF INNER BORE

ALL S/G(s) SCANNED FROM 90° TO 270° NOZZLE AZIMUTH (BOTTOM 180° OF NOZZLE)

RESULTS OF REGION 1 EXAMS:

- S/G 22: POSSIBLY 3 OF THE LONGEST CRACKS AND 2 GRINDOUTS OBSERVED
- S/G 21, 23 & 24: NO RELEVANT INDICATIONS

RESULTS OF REGION 2 EXAMS:

- S/G 21, 22, 23 & 24: NO RELEVANT INDICATIONS

RESULTS OF REGION 3 EXAMS:

- S/G 21, 22, 23 & 24: NO RELEVANT INDICATIONS

Table 3.1-5

INDIAN POINT UNIT 2

FEEDWATER NOZZLE

RT OF NOZZLE/PIPE JOINT

- ALL 4 S/G NOZZLE TO PIPE WELDS EXAMINED 100% BY RADIOGRAPHY
- NO RELEVANT INDICATIONS OBSERVED

Table 3.1-6

INDIAN POINT UNIT 2
FEEDWATER NOZZLES

VISUAL AND PT EXAMINATIONS OF FEEDWATER NOZZLE LOWER REGION DURING THE LINEAR INDICATION REMOVAL PROCESS

- S/G 22 & 23
- PT & FIBERSCOPE EXAMS DONE IN STEP-WISE FASHION DURING REMOVAL PROCESS
- ALL LINEAR INDICATIONS REMOVED (DEPTHS ON ORDER OF 0.1-0.2")
- VERIFIED BY PT & FIBERSCOPE EXAMS
- BRACKET WELD LINEAR INDICATIONS CURRENTLY BEING REMOVED

Table 3.1-7

3.2 Industry Experience

A summary of industry experience that is relevant to feedwater nozzle degradation provides insight into the probable causitive mechanism for the knuckle region cracking of the feedwater nozzle of SG 22. This is based on Westinghouse and Industry experiences to accomplish this objective (Table 3.2-1). These experiences also provide the basis for the inspections conducted as summarized in Section 3.1.

3.2.1 Feedwater Line Cracking

The first example of feedwater nozzle region degradation is the cracking that occurred in the pipe to nozzle joint area of several PWR steam generators. The primary mode of failure was concluded to be corrosion fatigue induced by the thermal conditions experienced at this location of the nozzle (Table 3.2-2). The cracking was most significant at the stress riser adjacent to the weld where a counterbore (and in some cases a counterbore with a backing ring) exists. Less severe cracking was also detected in the upstream and downstream directions (Figure 3.2-1). Cracking occurred at various locations around the pipe inner surface.

The thermal conditions that were concluded to have induced the cracking are illustrated in Figure 3.2-2. The upper half of the figure illustrates thermal stratification in the feedwater line, nozzle and feedring. This condition is created when cold water is injected into the feedsystem at low flow rates. This is usually associated with auxiliary feed flow. The cold, more dense fluid flows along the lower part of the pipe trapping hot water above it. The hot water is replenished by recirculating flow coming from inside the steam generator through the J-nozzles and through the annulus between the thermal liner and the nozzle inner bore. The thermal liner may also permit [

]a,c

The lower half of the figure is a trace of thermocouple data from an operating plant illustrating the corresponding feedwater flow rate trace. This type of data provided confirmation of the thermal condition since it shows a hot upper pipe simultaneously with a cold lower pipe with low flow followed by a totally cold pipe at higher flow and then by stratification once again when returning to the lower flow rate.

An additional loading mechanism, thermal striping, is also present at the interface between the hot and cold fluids. This mechanism is discussed more fully in a prior section and also in subsequent sections.

Near and long actions were taken by utilities to mitigate the thermal conditions. Near term actions were primarily to replace damaged hardware (replace in kind) with additional measures to improve counterbore geometry and oxygen control. Long term measures were either to protect the critical region or to mitigate the thermal conditions. The elbow thermal liner which [ ]^{a,c} provides protection to the critical region. Diverting the auxiliary feedwater flow through a smaller nozzles eliminates the conditions in the main feed nozzle and does not result in stratification in the smaller auxiliary nozzle. Heating the feedwater is another method incorporated to lessen the occurrence of stratification and also the temperature difference. A list of plants and the modification utilized is included in Figure 3.2-3 and Tables 3.2-3 to 3.2-5.

The following shows the occurrence of another example of feedwater nozzle cracking in Industry. A cross sectional view of a nozzle showing the slip fit between the feedwater ring thermal liner and the nozzle (Figure 3.2-4) is followed by a map of the indications removed by grinding in the nozzle inner bore near the knuckle region (Figure 3.2-5). This and each of the two examples that follow illustrate cracking that is attributed to excess bypass flow (or leakage) between the thermal liner and the nozzle liner bore. In this example, excess leakage occurred as a result of erosion of the liner at the slip fit joint. A bubble collapse waterhammer also occured that caused cracking of the liner.

Figure 3.2-6 to 3.2-8 illustrate the dimensions and configuration of an auxiliary nozzle of a typical PWR steam generator. In this example, the cracking occurred in the knuckle region of the nozzle as a result of leakage past the slip fit joint. The condition was eliminated by providing a modified liner design that incorporated a welded joint of the liner with the nozzle as shown in the third figure. A bubble collapse waterhammer was also associated with this failure.

The final example is also one of cracking associated with leakage flow which resulted in knuckle region cracking. Figure 3.2-9 illustrates the BWR nozzle cross section with the leakage flow designated behind the thermal liner. The figure also indicates that the knuckle region, where the cracking occurred, was subjected to high frequency thermal cycling, i.e., thermal striping. Figures 3.2-10 and 3.2-11 shows the flow patterns that provide the hot water for the cold feed flow to mix with and details of the design, respectively. Figure 3.2-12 is a schematic of a test model that provided confirmation of the mechanism and data that led to the modification to eliminate the mechanism. The modification was to eliminate the leakage flow at the slip fit joint.

a,c

GENERAL DESCRIPTION OF PITTING AND CRACKING AT PIPE TO NOZZLE JUNCTION

Figure 3.2-1

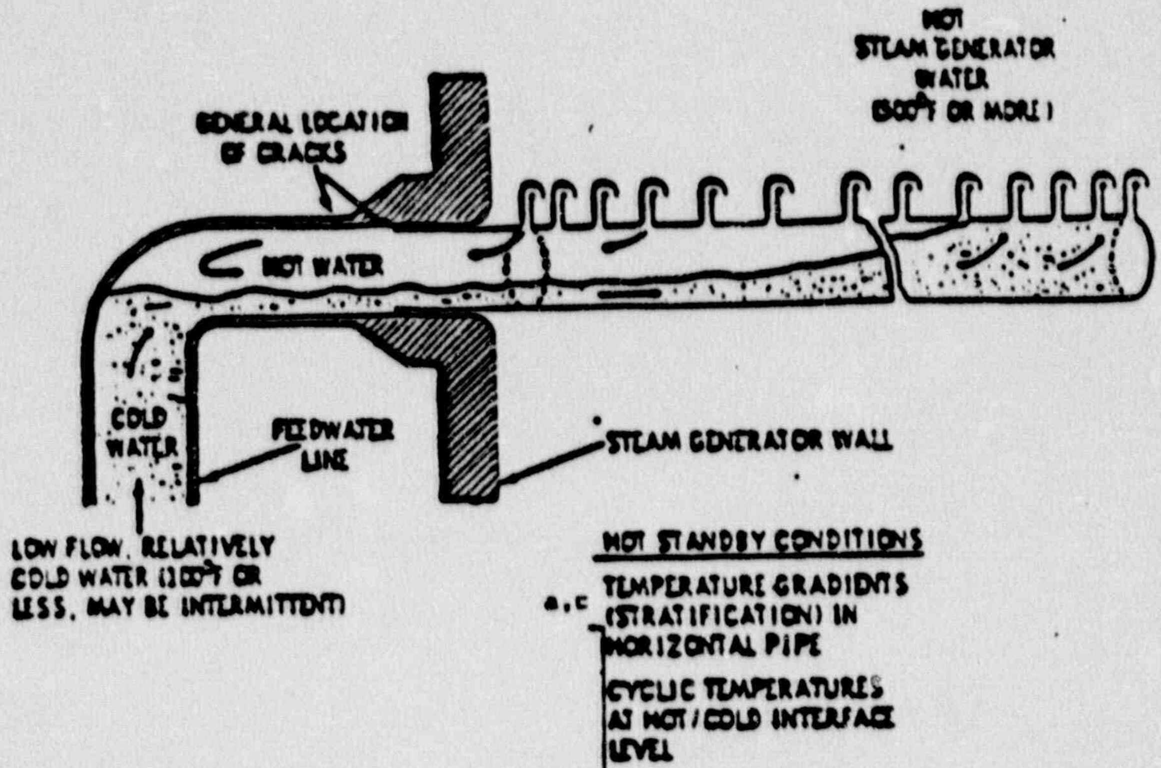

HOT
STEAM GENERATOR
WATER
OR MORE)
GENERAL LOCATION
OF CRACKS
HOT WATER
COLD
WATER
FEEDWATER
LINE
STEAM GENERATOR WALL
LOW FLOW, RELATIVELY
COLD WATER
OR
LESS, MAY BE INTERMITTENT)
HOT STANDBY CONDITIONS
TEMPERATURE GRADIENTS
(STRATIFICATION) IN
HORIZONTAL PIPE
CYCLIC TEMPERATURES
AT HOT/COLD INTERFACE
LEVEL
a,c

Figure 3.2-2

Short Term Action Plan

- Respond to IE-79-13, ISI
- Install New Pipe Elbows with Improved Counterbore Geometry
- Repair SG Nozzles: Pits, Cracks
- Maintain Oxygen Within Spec Limits

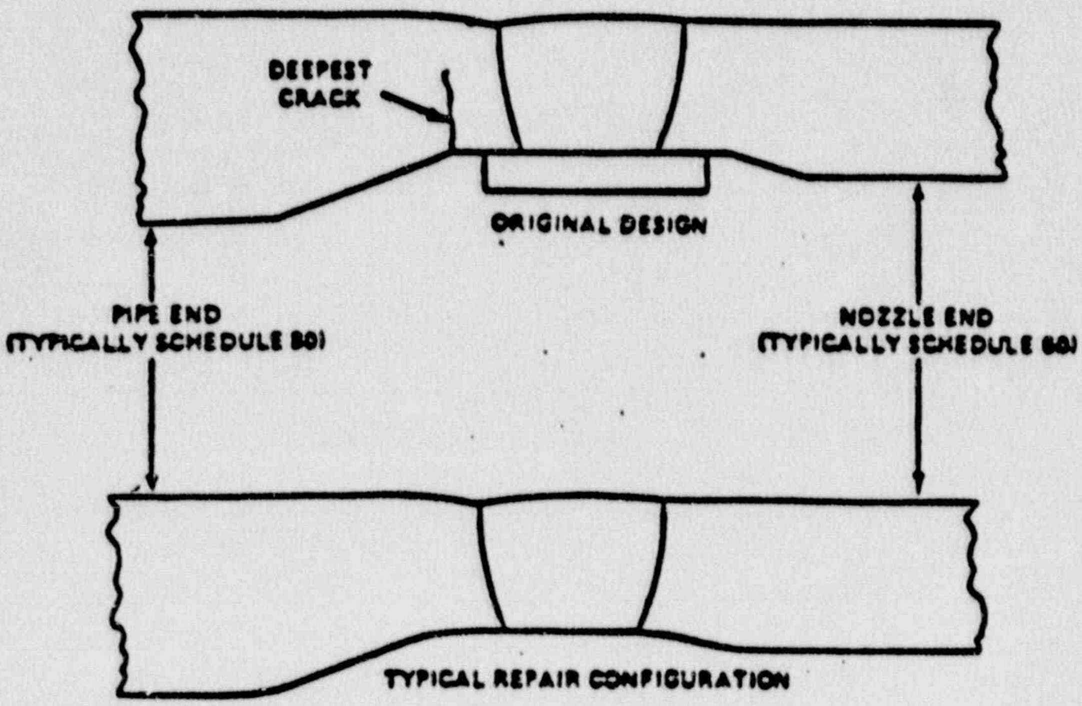


Figure 3.2-3

a,c

Figure 3.2-4.

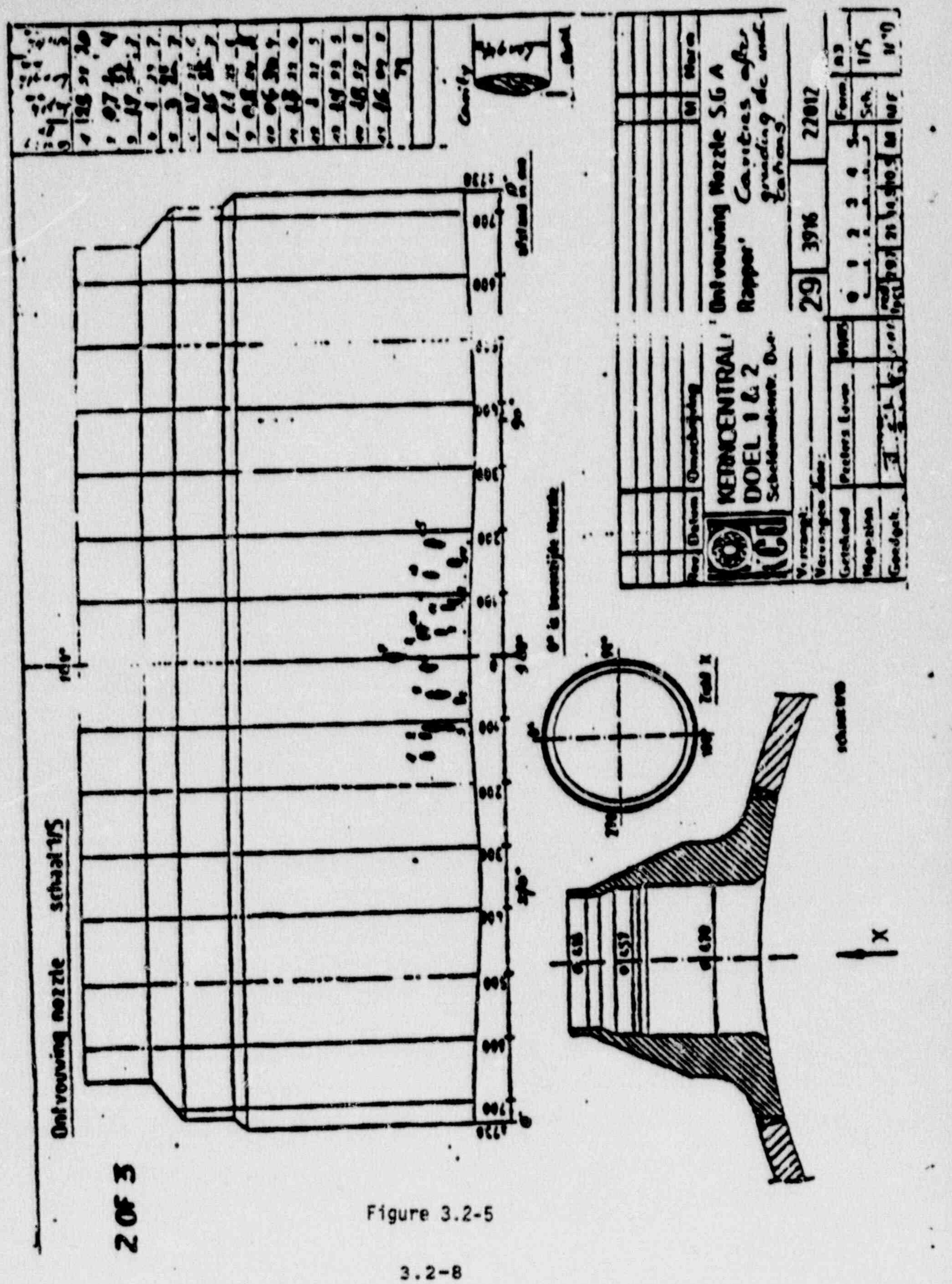

Ontvouwing nozzle
KERNCENTRALE
DOEL 1 & 2
Ontvouwing Nozzle S.G A
29
3916
220112
Cavity
2 OF 3

Figure 3.2-5

a,c

Figure 3.2-6

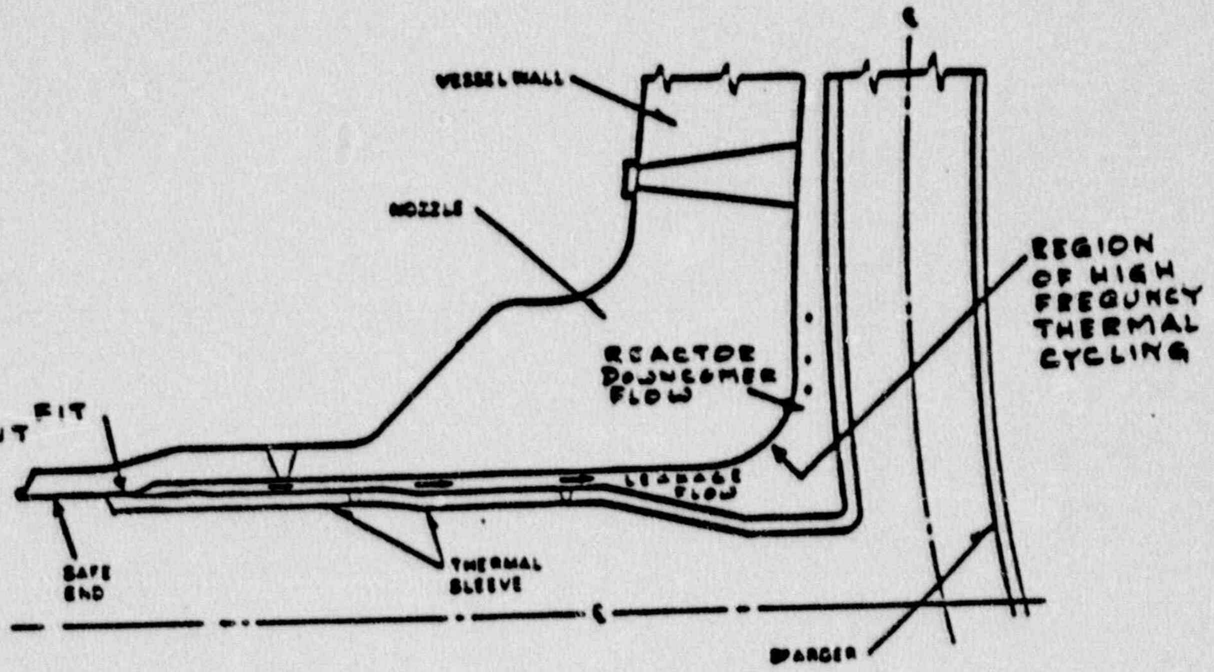
Auxiliary Feedwater Nozzle

a,c

Figure 3.2-7

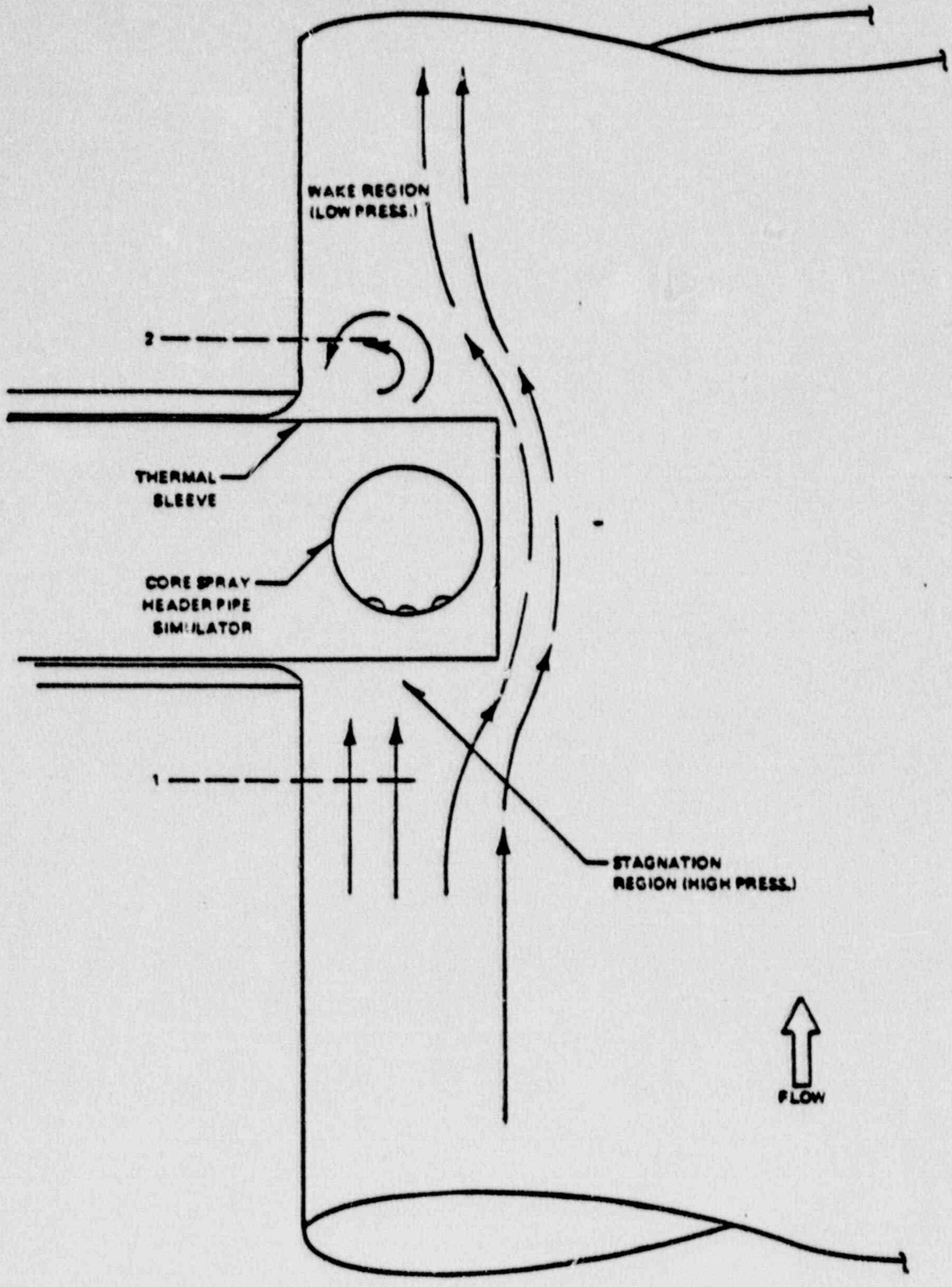
a,c

Figure 3.2-8

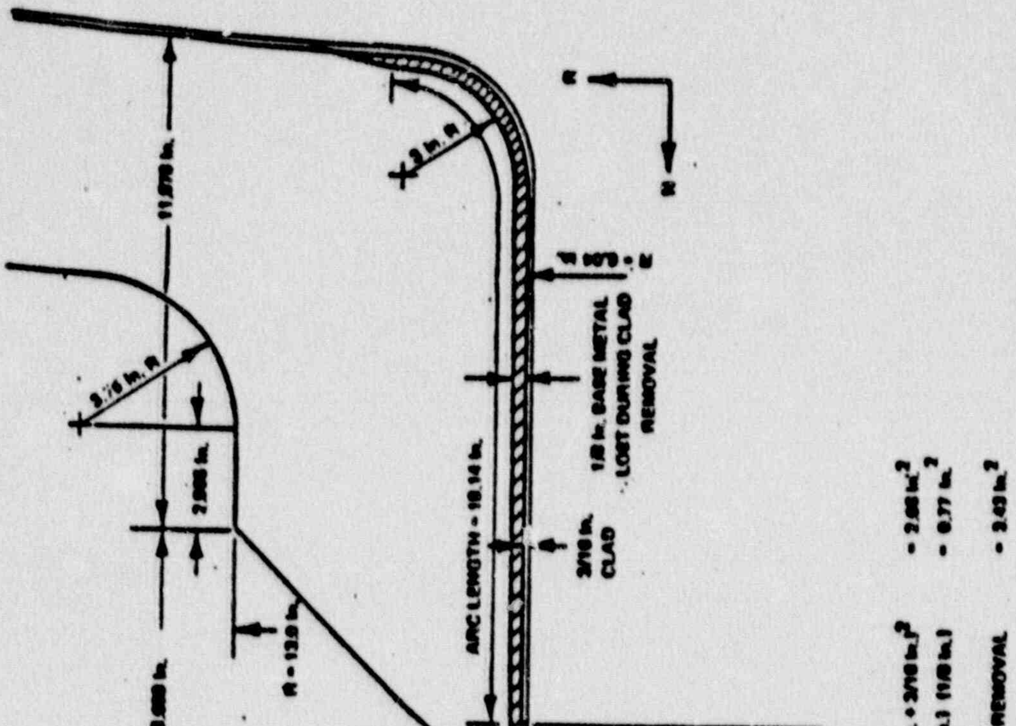


Schematic Diagram of the Feedwater Nozzle Sparger Configuration

Figure 3.2-9

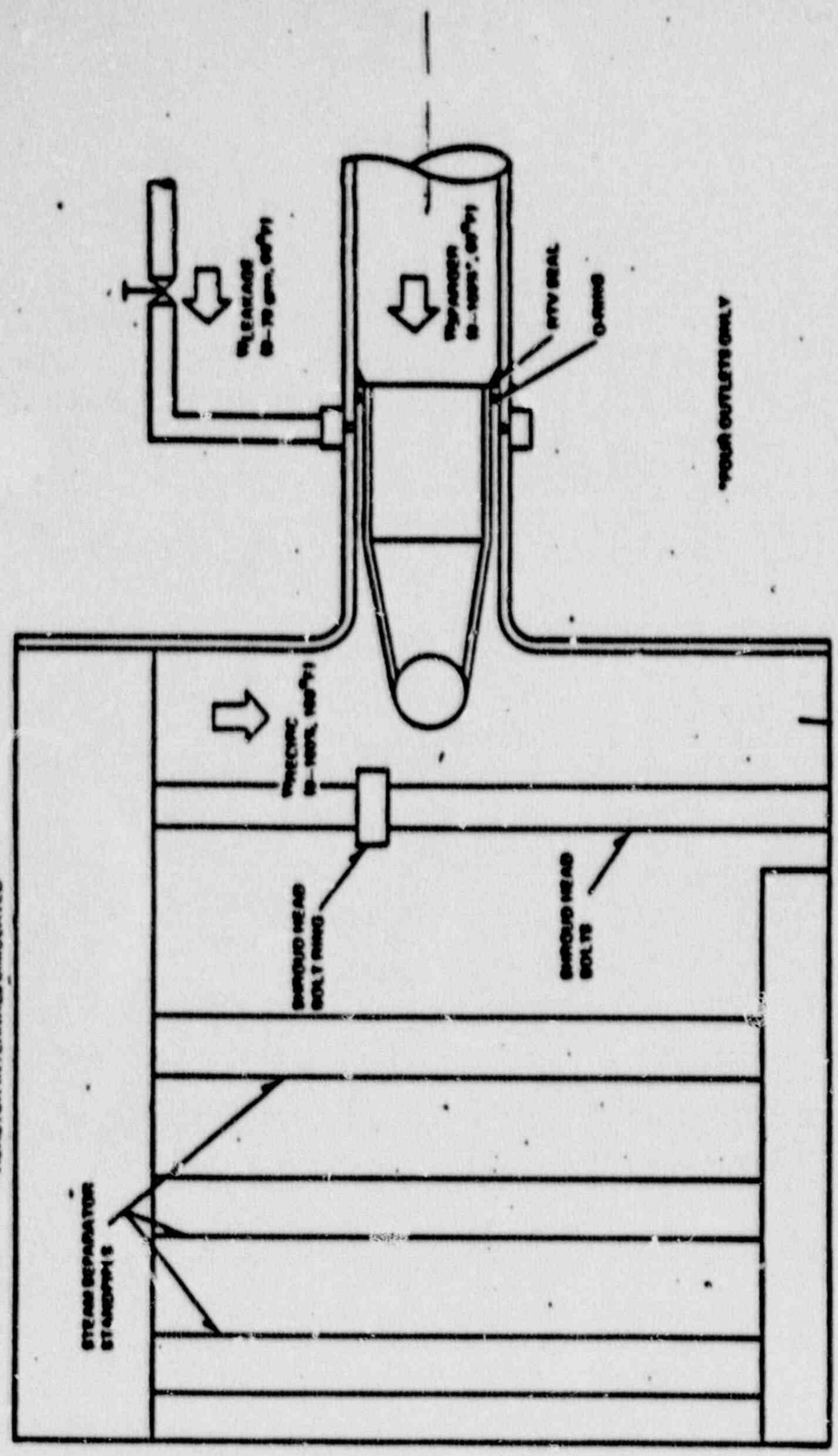


Pattern Past Thermal Sleeve and Header Pipe
Figure 3.2-10



Nozzle Reinforcement Deficit Due to Cladding Removal

Figure 3.2-11



Two Temperature Test Facility

Figure 3.2-12

INDUSTRY EXPERIENCE

PWR Steam Generators

Westinghouse

Competitor

BWR Reactor Vessels

Table 3.2-1

Feedwater Line Cracking

Cracks Have Been Found in the Nozzle/Pipe Interface Regions of Some Steam Generators

These Cracks are Primarily the Result of Fatigue Induced by Thermal Stratification and Steady-State Thermal Oscillations During Cold, Low Flow Feedwater Injections

The Primary Mode of Failure is Corrosion Fatigue

Table 3.2-2

Feedwater Line Cracking
Owner's Group Investigation
Conclusions

The Primary Loading Mechanisms are Thermal Stratification and Striping During Cold, Low Flow Feedwater Injections

---

The Primary Failure Mechanism is Corrosion-Fatigue Cracking

<u>Secondary Correlations</u>

- High Oxygen Concentrations from Condensate and Feedwater Make-up Systems
- Counterbore Geometry
- Thermal Cycles During Heat-Up, Hot Standby, and Low Power Operation
- Material Yield Strength at Operating Temperature

Table 3.2-3

Measures to Reduce Feedwater Line Cracking

a,c

Table 3.2-4

Feedwater Line Cracking
Field Modifications

a,c

Table 3.2-5

3.3 Root Cause Discussion

The characteristics of the nozzle cracks in the IP-2 generators in the knuckle area appear to be similar to those of the girth weld cracks, whose cracking mechanism was determined to be by corrosion fatigue.

Visual examination showed significant surface pitting with shallow cracks linking the pits. Corrosion product was observed in the cracks. Metallographic examination of the surface replicas taken from the affected regions showed the cracks to be transgranular.

There is also a growing experience of cracking in feedwater nozzles, both in PWR and BWR plants (Table 3.3-1). The cracking is determined to be a corrosion fatigue mechanism in each case with a direct correlation with the thermal conditions described (Table 3.3-2 and 3.3-3). There has been an identifiable relationship with oxygen ingress in some cases and with excess leakage flow due to erosion in other cases. The cracking is induced in several different locations but all within the general region of the feedwater nozzle. The reasons why cracking occurs in one zone over another is not fully understood but is probably related to the precise manner in which the cold flow is introduced into the generator as well as the precise fit up of the liner in the nozzle.

Based on industry experience (Table 3.3-4), the following examinations have been accomplished by Con Edison:

1. Inspect for cracking at the pipe to nozzle joint and along the nozzle inner bore.

2. Inspect for thermal liner erosion.

3. Grind out and blend all indications.

4. Determine fatigue usage and the acceptable operating period for reinspection.

For the long term, the effect of mitigating actions taken to address the girth weld condition should be assessed for its potential benefit to the nozzle and some means of sealing or providing a tighter joint between the nozzle and liner should be considered.

SUMMARY OF INDUSTRY EXPERIENCE

- Growing history of feedwater nozzle region cracking in PWR SG's
  - Nozzle/pipe joints
  - Inner bore
- History of feedwater nozzle region cracking in BWR reactors
  - Knuckle region
  - Inner bore

Table 3.3-1

Failure Mechanism

Corrosion fatigue

Direct correlation with cold water injections

Some correlation with high oxygen

In some cases correlated to thermal liner erosion

Table 3.3-2

Loading Mechanism

Crack initiation by stratification or striping

Crack propagation by stratification or pressure

Table 3.3-3

Recommendations For Mitigation

Short term

Inspect for cracking at pipe joint and along the inner bore

Inspect for thermal liner erosion

Grind out and blend all indications

Determine fatigue usage and operating period for reinspection

Long term considerations

Assess benefit of actions taken to mitigate girth weld cracking

Provide a tighter fitting thermal liner or a sealed liner

Table 3.3-4

3.4 Stress & Fatigue Evaluations

Reinforcement calculations have been performed to determine the maximum grinding depth permitted during the repair of the cracks observed in the shell side of the feedwater nozzle. Those calculations are summarized in Section 3.4.1.

A 3-D finite element analysis has been performed to determine the contribution of thermal stratification in the feedline to the cracks observed in the feedwater nozzles and to assess the susceptibility of the proposed repair geometry to fatigue damage. This analysis is summarized in Section 3.4.2.

Finally, the effect of mitigating actions being considered for the girth weld condition is assessed relative to the feedwater nozzle (Section 3.4.3).

3.4.1 Feedwater Nozzle Material Removal

The maximum allowable depth for material removal from the inside surface of the Series 44 Steam Generator feedwater nozzle is obtained by requiring that the reinforcement area of the repaired nozzle satisfy the ASME Code limit as specified in the original stress report. This assures that the primary stress limits are still satisfied as in the original stress report.

The required reinforcement is given by:

$$A_{req} = d\, t_R F + 2\,(1 - \pi/4)\, R^2$$

where:

d = Diameter of the finished opening in its corroded condition = $[18.5 + 2\,(0.065) = 18.63 \text{ in.}]^{a,c}$

t_R = Required shell wall thickness = $[3.365.]^{a,c}$

F = 1, when the plane under consideration contains the longitudinal axis of a cylindrical shell. F < 1 for all other planes.

R = Inside corner radius = [ ]^{a,c}

With these dimensions, the required reinforcement area for the original nozzle is [ ]^{a,c}

The limits of reinforcement are specified by:

a. Measured along the midsurface of the nominal wall thickness, the limit of reinforcement shall be at a distance, on each side of the axis of the opening, equal to the greater of the following:

   1. The diameter of the finished opening in the corroded condition [ ]^{a,c}

   2. The radius of the finished opening in the corroded condition, plus the thickness of the shell wall, plus the thickness of the nozzle wall [ ]^{a,c} In the present case this limit is therefore [ ]^{a,c}

b. Measured normal to the vessel wall, the limit of reinforcement shall conform to the contour of the surface at a distance from each surface equal to:

   0.5 [ ]^{a,c}

where:

r_m = Mean radius = r_i + 0.5 t
r_i = Inside radius = [ ]^{a,c}
t = Nominal nozzle thickness = [ ]^{a,c}
R_2 = Transition radius between nozzle and wall = [ ]^{a,c}

Substituting into the above equation, this limit of reinforcement is 6.33 in. The available reinforcement is therefore, based on the sketch in Figure 3.4-1, [ ]^{a,c} These calculations are summarized in Table 3.4-1.

The relationships above are used to determine the maximum metal removal allowed while still satisfying reinforcement requirements. Assuming a depth of material removal from the nozzle as shown in Figure 3.4-2, an iterative solution of the reinforcement area calculations results in a maximum permissible removal depth of 0.40 in. The results of these calculations are summarized in Table 3.4-2. Note that both of the above reinforcement calculations use a knuckle radius of [ ]^{a,c} The as-built dimension is approximately [ ]^{a,c} This provides extra margin as illustrated in Figure 3.4-3.

3.4.2 Feedwater Nozzle Fatigue Usage

A 3-D finite element analysis has been performed to determine the contribution of thermal stratification in the feedline to the cracks observed in the Indian Point 2 feedwater nozzle and to assess the susceptibility of the proposed repair geometry to fatigue damage (Table 3.4-3).

Two models were generated, one for the original geometry of the feedwater nozzle, and a second for the idealized configuration of a 0.4 inch deep groove with [ ]^{a,c} at each end and along the sides. The second figure of the Area of Reinforcement section contains a sketch of this groove. Two views of the finite element models are shown in Figure 3.4-4. An enlargement of the model of the nozzle is shown in the Figure 3.4-5. Both finite element models are identical except for the groove in the second model. That area is shown cross-hatched in Figure 3.4-5.

The loads applied to these models were pressure, six thermal stratification profiles, and steady state conditions from two system transients (100% Power and Loss of Power). Since the main area of concern was the knuckle region and shell face of the nozzle, pipe loads and feedwater thermal transients were not considered.

Figures 3.4-6 and 3.4-7 show the fluid temperature within the nozzle for each of the six stratification profiles. The cross-hatched areas indicate the location of the interface between the hot and cold fluids. These profiles were based on data obtained from five operating plants during the feedwater line cracking investigation performed during 1979-1980.

The thermal liner was installed inside the feedwater nozzle with a small clearance slip fit at its end. With no seal between the liner and nozzle, a leak path exists between the liner and nozzle allowing some of the feedwater to flow into the annulus between the two components. This bypass flow becomes more pronounced as the feedwater temperature decreases. Figure 3.4-8 shows the elements in the finite element models assumed to be exposed to this bypass flow for each of the stratification profiles.

During hot standby operation (when thermal stratification in the feedline occurs), Indian Point 2 adds feedwater continuously at a low flow rate. Not having the stratification data for this plant to determine the variation of interface levels and top-to-bottom temperature differences during a typical hot standby period, data from a plant with similar operating practices was used for the stratification history at Indian Point 2. The data obtained during the test period was extrapolated to the number of hours Indian Point 2 has operated in hot standby condition to date (9764 hours).

The load conditions contributing to fatigue usage of the feedwater nozzle are based on the actual operating history of Indian Point 2. These are listed in Table 3.4-4. The scale factor in the last column is the amount by which the stresses from the thermal condition referred to in the next to last column are multiplied. The stratification condition typically consists of three or four separate delta T's for each of the six profiles.

Table 3.4-5 presents the results for the maximum range of primary plus secondary stress intensities for both the original and idealized repair geometries. The locations evaluated are the shell face of the nozzle (ASN's 102-146) and the bottom part of the nozzle bore near the knuckle (ASN's 1-6), Figure 3.4-9.

The $3S_m$ limit is based on the minimum ultimate strength and yield strength properties of the actual material used for the nozzle per the material certification records of the nozzle forging. This material is covered by Code Case 1332-1, 8/11/64. Based on the material certifications, a minimum S_m of 28.83 Ksi is justified.

The maximum range of stress intensity including thermal bending exceeds $3S_m$ at several locations. The ASME Code permits this as long as the procedures of NB-3228.5 are followed. This was done in the calculation of the fatigue usage factors reported below. Fatigue penalty factors, K_e, were calculated and used in determining the alternating stresses. NB-3228.5(a) requires that the range of primary plus secondary membrane plus bending stress intensities with thermal bending stresses removed be less than $3S_m$. These calculations were performed and the results listed in Table 3.4-5. All values are less than $3S_m$. The other conditions of NB-3228.5 are also satisfied.

The grooved geometry analyzed introduces a local structural discontinuity. Thus any additional stress caused by the presence of the groove is classified as a peak stress and is not included in the range of primary plus secondary stress intensity (ASME Code Section III, NB-3213.11(c)). The results of this evaluation therefore apply both to the original geometry and to the grooved geometry.

Table 3.4-6 lists the fatigue usages calculated for different regions of the feedwater nozzle for both the original geometry and for the idealized repair geometry. The fatigue usage for the original geometry is based on actual operating history to date (16.21 years). These fatigue usages include the effect of bypass leakage flow through the liner-nozzle annulus. Since the calculated fatigue usage in the area of the observed cracks (shell face of knuckle) is significantly less than one, stratification alone cannot account for the cracking. Since the stratification history is not expected to be as severe as that assumed for this analysis, the additional phenomenon of striping is most likely the principal cause of the cracking. This is supported by the experiences noted in Section 3.2.

The fatigue usages calculated for the idealized repair geometry are based on an extrapolation of the data in the load condition table for a ten-year operating period. These fatigue usages also include the effect of bypass leakage flow through the liner-nozzle annulus. The critical location is in the bottom of the groove and does not include any striping effect. Striping should occur at the edges of the bypass flow away from the groove.

With a usage of 1.44 in ten years for the idealized groove geometry without any usage due to striping, it will take approximately 7 years before a fatigue usage of 1.0 is reached. The fatigue usage due to striping [ ]a,c would not change significantly with the change in thickness. Striping solutions using [ ]a,c (as described in Section 2.5.5 and Table 2.5-8) have shown that the stress amplitude response of the metal surface does not change significantly above a thickness of about 1.0 inch. At the large thicknesses of the knuckle region (>5 inches), the small amount of metal removed by grinding has negligible effect on the stress amplitude response. This is due to the fact that the surface stress is a direct function of surface temperature minus the mean temperature of the total metal thickness. Neither of these change significantly from one thickness to another when the sections are thick. Therefore, without mitigating actions, cracking away from the local groove would be expected to occur in the same operating period as it did initially, i.e., about sixteen years (Table 3.4-7).

If however, we make the conservative assumption that the fatigue usage calculated for the grooved geometry is additive to usage due to striping, we would expect about 5 years of operaton without degradation. Assuming a current combined usage of 1.0 for the original geometry would mean that a usage of 0.78 is due to striping. Usage due to striping in ten years is (10/16) x 0.78 = 0.49. There is negligible current usage due to striping since the damaged metal has been removed. Adding this to the usage in the groove gives a total usage of 1.44 + 0.49 = 1.93 in ten years. The current usage due to stratification is less than the calculated 0.22 since, again, the most highly damaged material has been removed. Conservatively adding this 0.22 gives a ten year combined usage of 2.15. A usage of 1.0 would therefore be reached in about 5 years.

3.4.3. Potential Effect of Girth Weld Actions

Actions taken to mitigate the girth weld condition (Table 3.4-8) would also, for the most part, provide a benefit to extending the time to crack at the feedwater nozzle knuckle region. Providing heated water through a main feed bypass simultaneously with auxiliary feedwater injections would be beneficial. Providing more stringent control on any source of oxygen ingress into the auxiliary feed system may be a benefit. Removing the DCRP is not likely to benefit the feedwater nozzle.

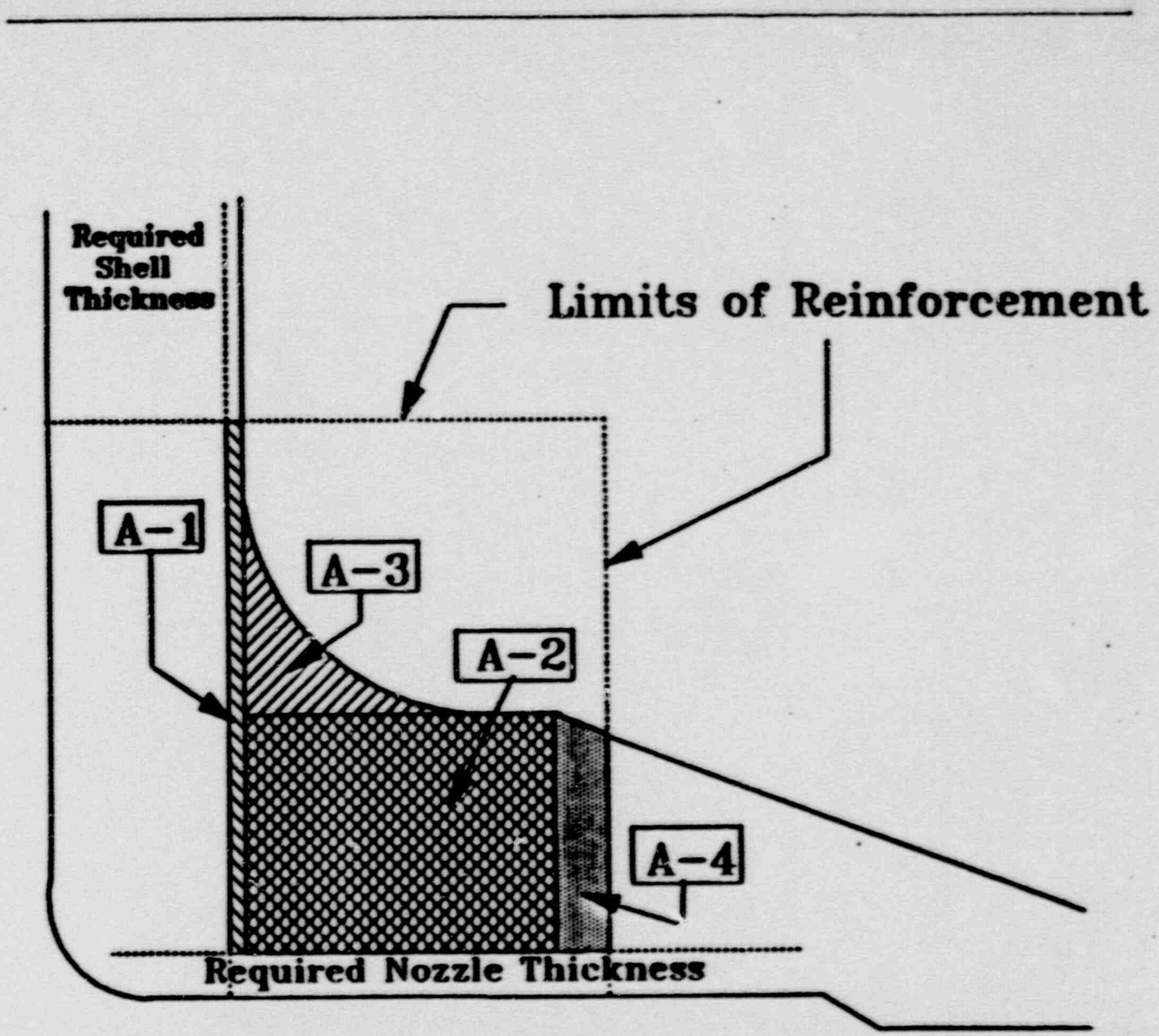

Required
Shell
Thickness
Limits of Reinforcement
A-1
A-3
A-2
A-4
Required Nozzle Thickness

Figure 3.4-1

a,c

Figure 3.4-2

a,c

Figure 3.4-3

FEEDWATER NOZZLE FINITE ELEMENT MODEL

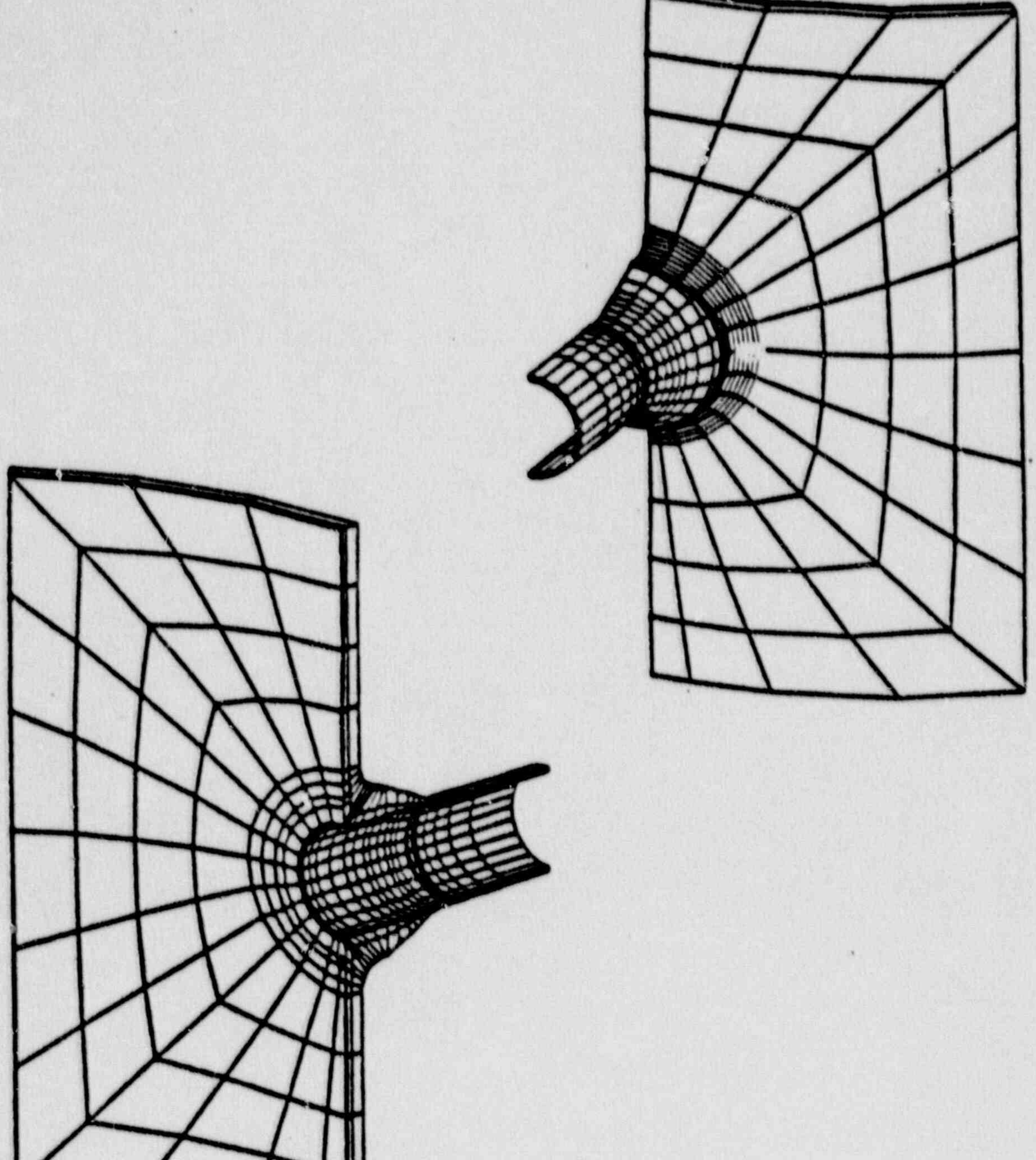


Figure 3.4-4

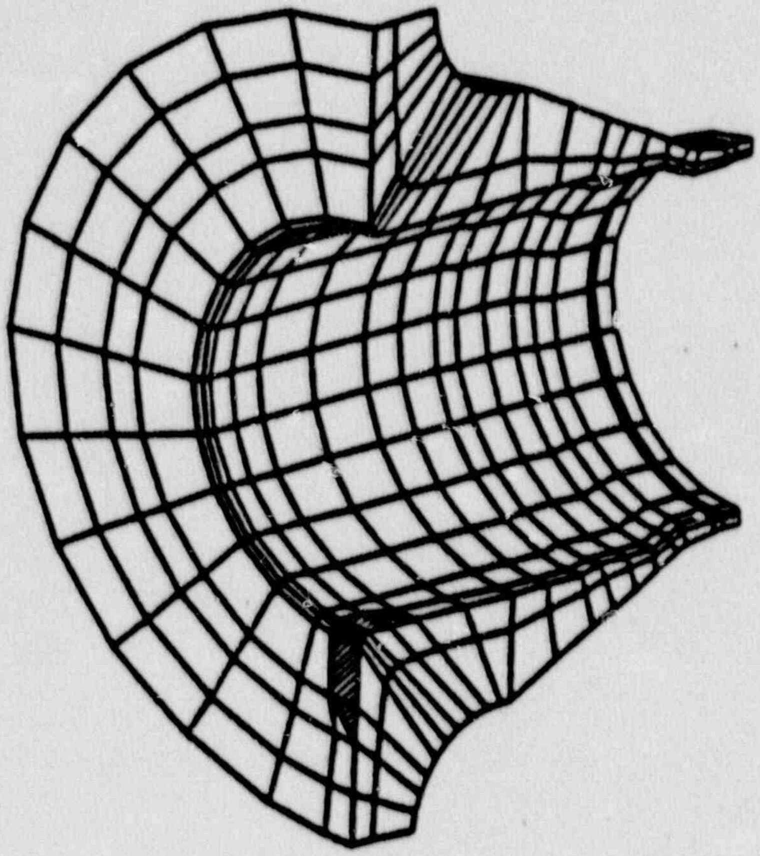


Figure 3.4-5

FEEDWATER STRATIFICATION PROFILES

a,c

Figure 3.4-6

FEEDWATER STRATIFICATION PROFILES

a,c

Figure 3.4-7

BYPASS FLOW THROUGH SLEEVE/NOZZLE ANNULUS DURING STRATIFICATION

a,c

Figure 3.4-8

WESTINGHOUSE PROPRIETARY CLASS 2

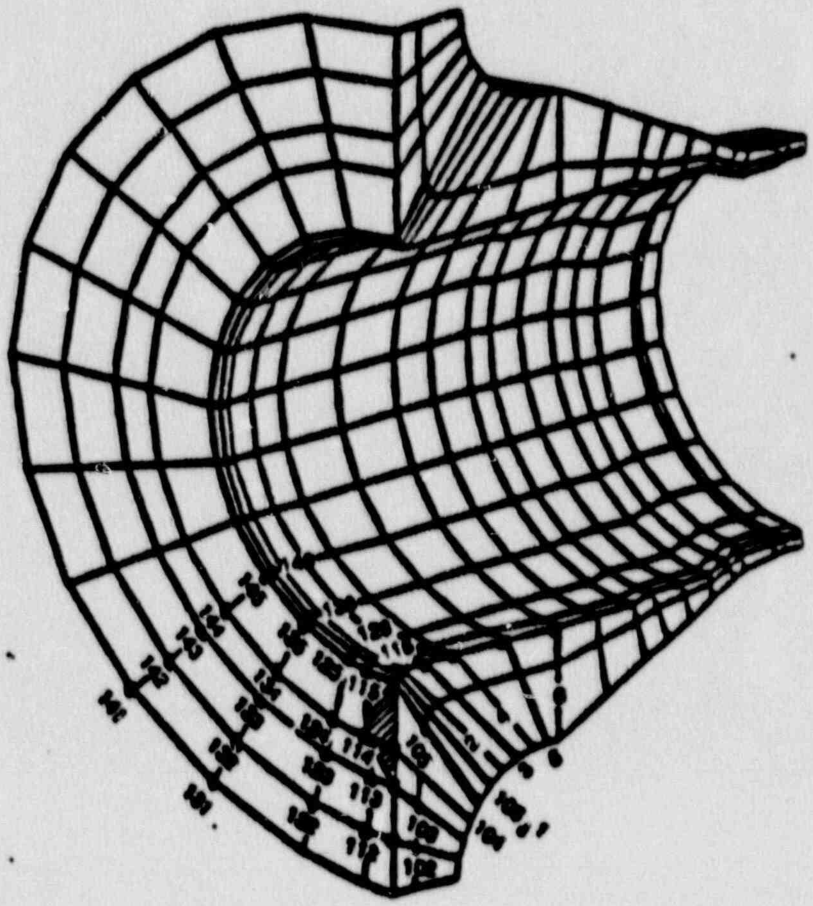


FIGURE 3.4-9 ASN LOCATIONS

44 SERIES STEAM GENERATOR FEEDWATER NOZZLE

NOMINAL REINFORCEMENT CALCULATIONS

a,c

Table 3.4-1

44 SERIES STEAM GENERATOR FEEDWATER NOZZLE

a,c

Table 3.4-2

IPP FEEDWATER NOZZLE EVALUATION

ORIGINAL CONFIGURATION

- 3-D FINITE ELEMENT MODEL
- LOADING CONDITIONS
  - Pressure
  - Thermal Stratification (6 Profiles)
    - No Bypass Flow Through Annulus
    - With Bypass Flow
  - System Transients (Steady State)
- FATIGUE EVALUATIONS
  - Area of Observed Cracks
  - Nozzle Bore
  - End of Thermal Sleeve
  - Nozzle Safe End Counterbore
  - Pipe Counterbore

IDEALIZED REPAIR CONFIGURATION

- 3-D FINITE ELEMENT MODEL
- LOADING CONDITIONS
  - Pressure
  - Thermal Stratification (6 Profiles)
    - No Bypass Flow Through Annulus
    - With Bypass Flow
  - System Transients (Steady State)
- FATIGUE EVALUATIONS
  - Area of Observed Cracks
  - Nozzle Bore

Table 3.4-3

IPP FEEDWATER NOZZLE LOAD CONDITIONS

EVENTS TO DATE (3/89)

Load Condition	Number	Pressure	T_{sat}	T_{fw}	ΔT	Thermal Condition	Scale Factor
Ambient[1]	97	0	70	70	0	None	
Hot Standby (No Flow)	402	1005	547	547	0	None	
Stratification[2]	9764	1005	547	Varies	Varies	Stratified	
100% Power	1382	762	514.9	416	98.9	100% Pwr	
75% Power[3]	1382	984	542	250	292	100% Pwr	
Small Step Load Inc	42	675	501.5	408	95.5	100% Pwr	
Small Step Load Dec	80	861	528.8	416	112.8	100% Pwr	
Large Step Load Dec	34	988	545	200	345	100% Pwr	
Reactor Trip	447	988	545	70	475	Loss of Pwr	
Loss of Load	22	1046	551.8	70	481.8	Loss of Pwr	
Loss of Power[4]	14	1005	547	70	477	Loss of Pwr	
Secondary Hydrotest	1	1356	70	70	0	None	
Secondary Pressure Test	20	1085	70	70	0	None	

a,c

1 Number of heatups plus number of test conditions

2 Number of occurrences refers to hours at hot standby during which stratification can occur.

3 Added to provide end point for load/unload transients.

4 Includes Loss of Flow, Control Rod Drop, and Turbine Roll Test

Table 3.4-4

TABLE 3.4-5
IPP FEEDWATER NOZZLE - MAXIMUM RANGE OF STRESS INTENSITY ORIGINAL AND REPAIR GEOMETRIES

ASN	NODE	MAX RANGE	LIMIT
102	2135	52.53	86.50
103	2535	60.69	86.50
104	2935	66.39	86.50
105	3335	81.68	86.50
106	3735	83.62	86.50
112	2125	54.15	86.50
113	2525	58.04	86.50
114	2925	66.41	86.50
115	3325	81.24	86.50
116	3725	83.19	86.50
122	2115	54.75	86.50
123	2515	59.81	86.50
124	2915	63.48	86.50
125	3315	79.91	86.50
126	3715	81.73	86.50
131	1705	53.77	86.50
132	2105	66.53	86.50
133	2505	55.51	86.50
134	2905	62.17	86.50
135	3305	75.15	86.50
136	3705	75.97	86.50
141	1695	45.96	86.50
142	2095	61.56	86.50
143	2495	50.02	86.50
144	2895	56.40	86.50
145	3295	67.76	86.50
146	3695	68.58	86.50
1	3735	83.48	86.50
2	4135	83.73	86.50
3	4535	69.11	86.50
4	4935	53.28	86.50
5	5335	50.04	86.50
6	5735	27.35	86.50

FATIGUE USAGE

ORIGINAL GEOMETRY

Location	Fatigue Usage Factors
Bottom of Nozzle Bore near Knuckle	0.204
Nozzle Knuckle	0.260
Shell Face of Knuckle	0.222
Nozzle Land at End of Sleeve	0.176
Nozzle Counterbore	0.027
Pipe Counterbore	0.095

IDEALIZED REPAIR GEOMETRY

Location	Fatigue Usage Factors
Bottom of Nozzle Bore near Knuckle	0.854
Nozzle Knuckle	1.170
Shell Face of Knuckle	1.440

Table 3.4- 6

FATIGUE USAGE CONCLUSIONS

WITH INTERMITTENT FW CYCLING
(WITHOUT STRIPING)

ABOUT 7 YEARS TO REACH A FATIGUE USAGE OF 1.0 WITH ANNULAR LEAKAGE FLOW

STRIPING EFFECT

STRESSES DUE TO STRIPING WOULD NOT CHANGE SIGNIFICANTLY

Table 3.4-7

POTENTIAL EFFECT OF GIRTHWELD ACTIONS

FEEDWATER CONTROL

SHOULD BE BENEFICIAL

REMOVE DOWNCOMER PLATE

NO EFFECT

PROVIDE MAIN FEEDWATER

SHOULD PROVIDE SOME BENEFIT

Table 3.4-8

3.5 Fracture Mechanics Evaluation - Feedwater Nozzle

Tables 3.5-1 through 3.5-7 and Figures 3.5-1 to 3.5-4 were presented at the May 11, 1988 Con Ed/NRC Meeting.

The fracture evaluations performed for the feedwater nozzle were similar to those performed on the girth weld. In this section we will discuss the cross section examined, the critical flaw depth calculations and fatigue crack growth results. In addition, a safety assessment will be performed to demonstrate leak-before-break for flaws which might exist in this region.

A finite element analysis was conducted for the feedwater nozzle region as discussed earlier, using the actual nozzle knuckle radius as measured on the generators. The geometry is shown in the figure and would also include the 3 cross sections chosen for analysis. The cross sections have been denoted by the node number of the finite element model at the inside surface of the cut. These cross sections are shown clearly in the figure.

1) Critical Flaw Depth Calculation

The fracture analysis to determine the critical flaw depth followed the same procedure as for the girth weld. The governing transient, as before would be the reactor trip. The lowest metal temperature is again 260°F. The RTNDT for the nozzle forging material was found to be no greater than 60°F, therefore again the fracture toughness is on the upper shelf of the K_{1R} curve and also assumed to be 200 KSI root in. The critical flaw depths calculated for the feedwater nozzle region are shown in the table for 3 different aspect ratios. The critical flaw depth for a very long flaw (length 20 times the depth) ranges from 18.5 to 46% of the wall thickness depending on location. For flaws with a length six times the depth the critical depth was determined to range from 28 to 68% of the wall thickness. For a semi-circular surface flaw, results showed that the stress intensity factor did not exceed the fracture toughness for flaws postulated with depths up to the thickness.

2) Fatigue Crack Growth

The fatigue crack growth analysis carried out for the feedwater nozzle followed the same procedure as that used for the girth weld. The stresses were the same as was used in the fatigue analysis of the nozzle reported earlier. The transients included a full duty cycle. The fatigue crack growth analysis used the reference crack growth curves of ASME Section XI. The same 3 cross sections were analyzed for fatigue crack growth as for critical flaw size. The results were shown in the three figures for postulated initial crack depths of .05". The results of the fatigue crack growth analysis show very little fatigue crack growth for a typical 14 month to 24 month refueling cycle.

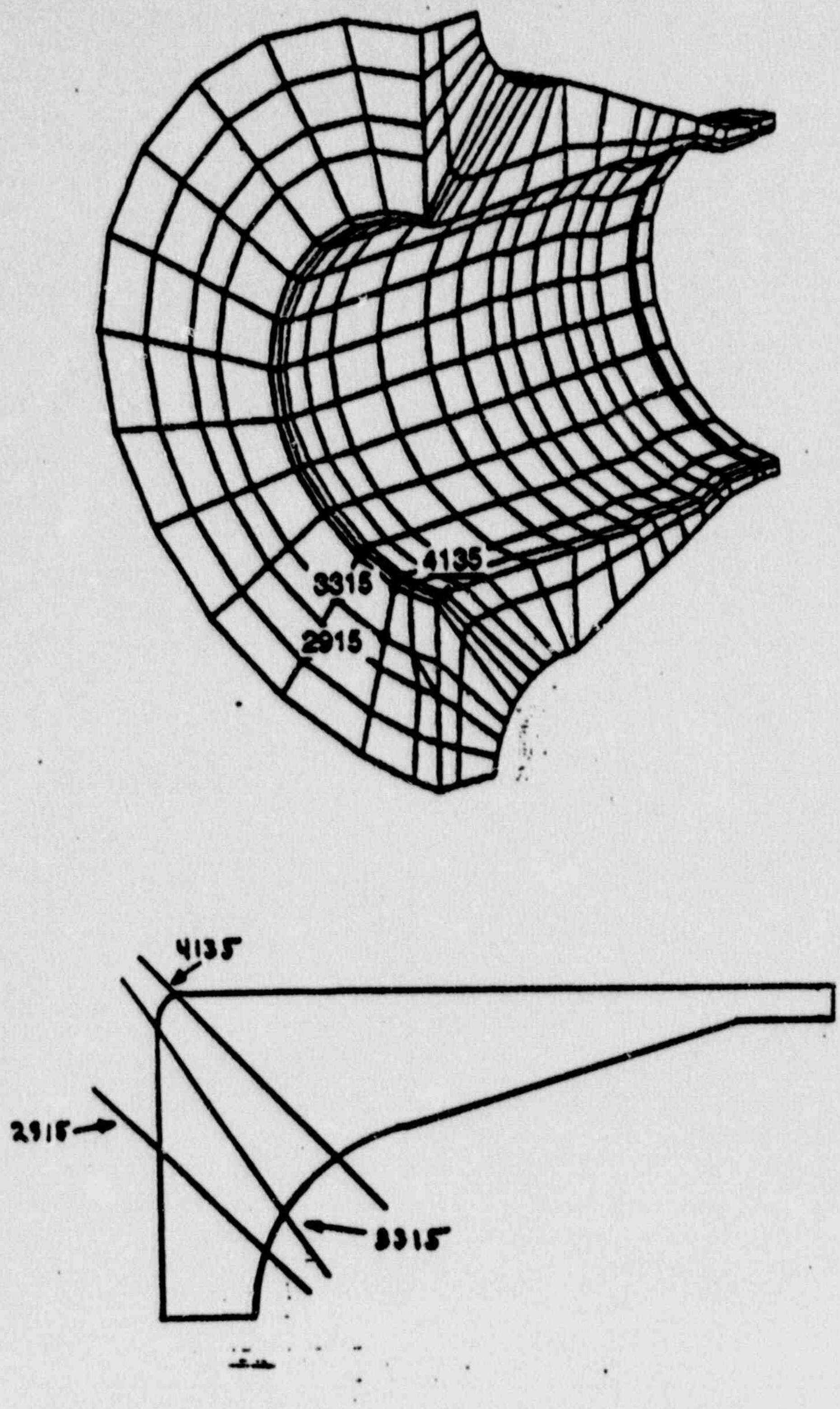
3) Leak-Before-Break Safety Assessment

The leak-before-break assessment for the feedwater nozzle region was carried out in a very similar fashion to the assessment for the girth weld. The governing transient is again the reactor trip and the stress intensity factor (K) was calculated as follows:

[ ]^{a,c}

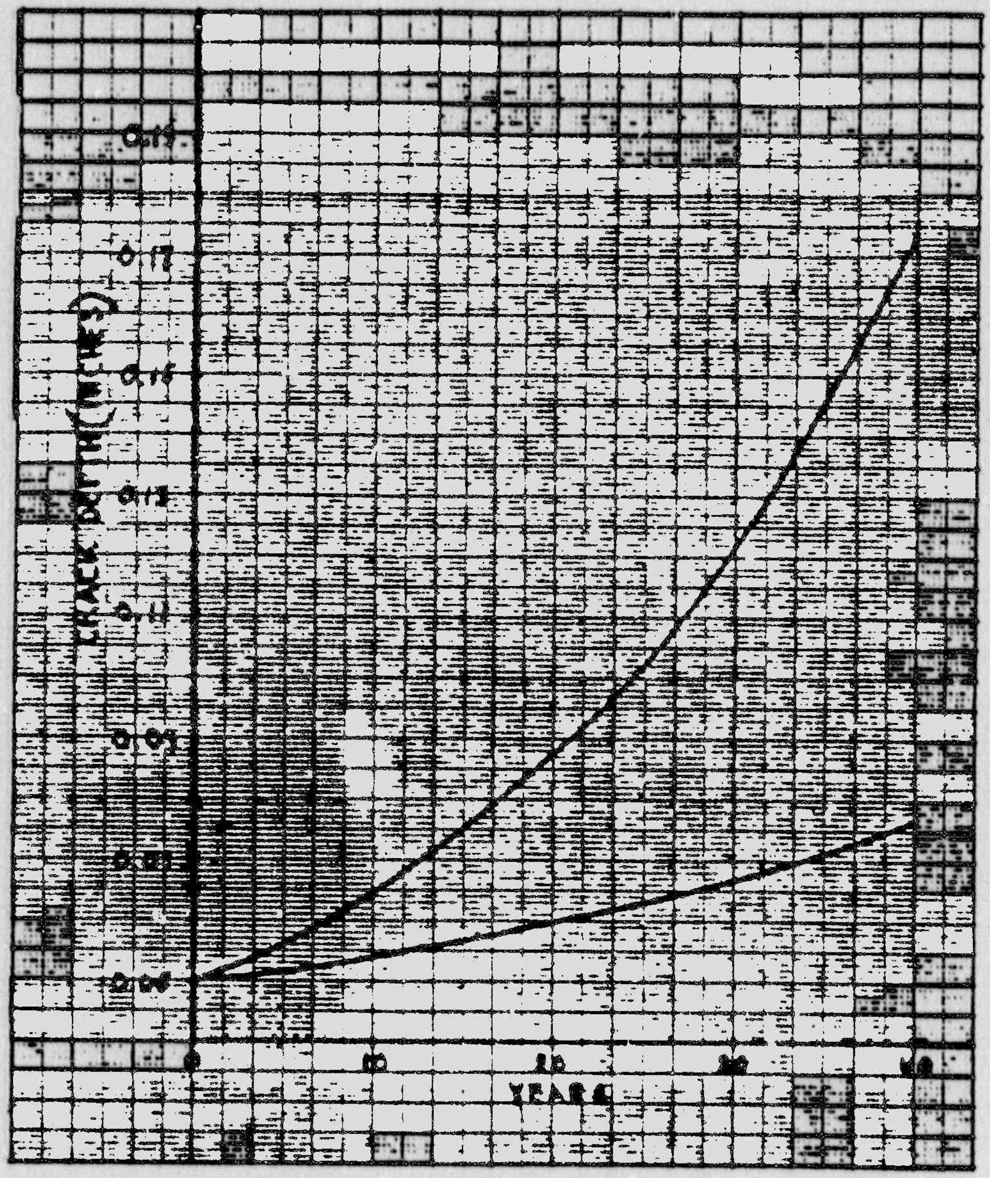
where sigma = applied stress and a = 1/2 length of the through wall flaw. The fracture toughness used in the LEFM analysis was taken as 200 KSI root in.

The results of the instability flaw calculations using LEFM showed a critical length of 4.8". The critical length determined using a ductile fracture evaluation (limit load) was found to be 217 inches. The true critical flaw length is expected to be between these two values, and closer to the ductile value. Therefore, we conclude that measurable leakage will occur long before the critical length is reached.



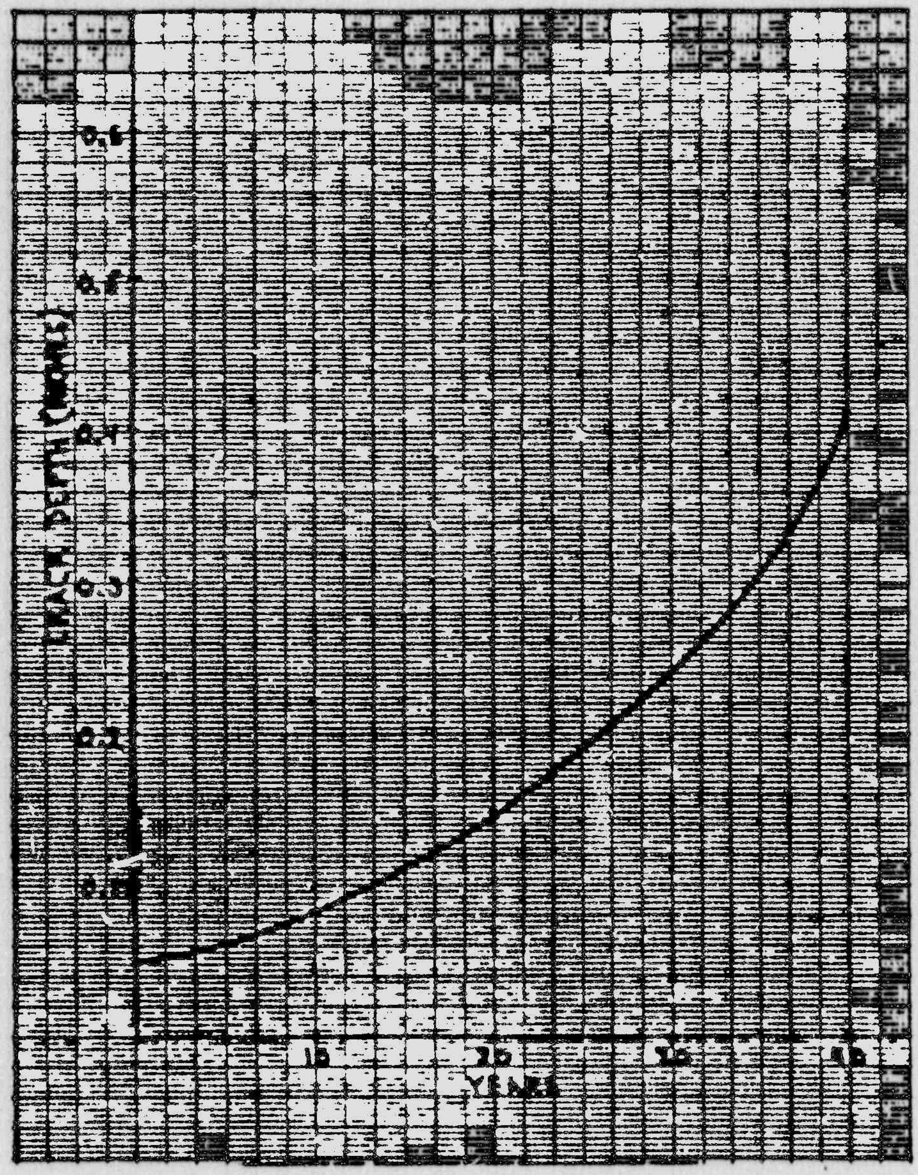
FEEDWATER NOZZLE GEOMETRY

Figure 3.5-1



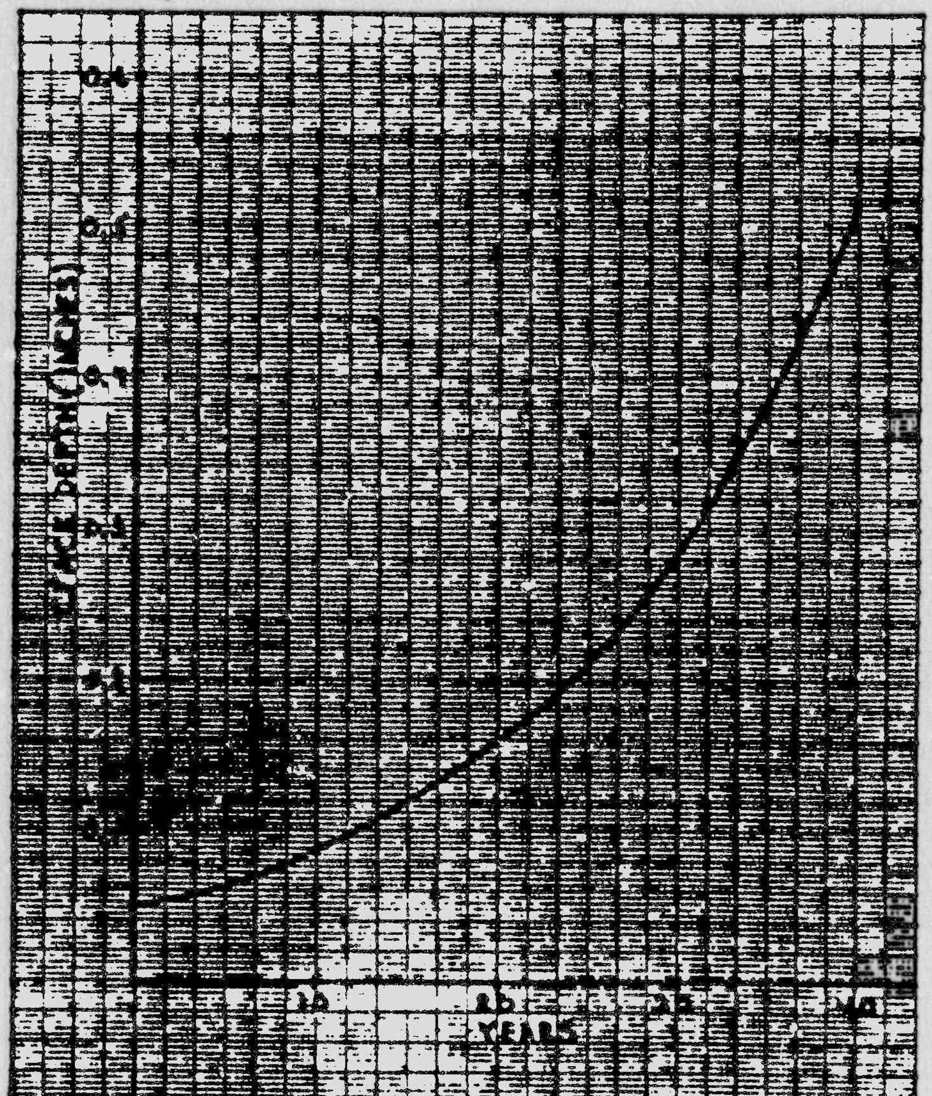
Fatigue Crack Growth Results: Shell Side (2915)

Figure 3.5-2



Fatigue Crack Growth Results: Nozzle Knuckle (3315)

Figure 3.5-3



Fatigue Crack Growth Results: Nozzle Bore (4135)

Figure 3.5-4

E. FRACTURE MECHANICS EVALUATIONS, FEEDWATER NOZZLE

- Cross Sections Examined
- Allowable Crack Depth
- Crack Growth Results
- Leak Before Break
- Recommendations

Table 3.5-1

ALLOWABLE CRACK DEPTH

Material: A508 Class 2

Fracture Toughness:	Use K_{IR} Curve
	Upper Shelf Toughness:
	200 Ksi $\sqrt{in}$
Governing Transient:	Reactor Trip
	Lowest Temperature: 260°F

Table 3.5-2

CRITICAL FLAW DEPTHS - FEEDWATER NOZZLE REGION

REACTOR TRIP TRANSIENT

Cross Section	Critical Depth (Inches)	Critical Depth (Percent Wall)
Aspect Ratio 20:1		
Bore (4135)	2.99	46
Knuckle (3315)	1.43	18.5
Shell Side (2915)	2.19	38
Aspect Ratio 6:1		
Bore (4135)	4.42	68
Knuckle (3315)	2.17	28
Shell Side (2915)	3.63	63
Aspect Ratio 2:1		
Bore (4135)	6.5	100
Knuckle (3315)	7.75	100
Shell Side (2915)	5.77	100

Table 3.5-3

FATIGUE CRACK GROWTH

- Stresses Taken From Fatigue Analysis - Full Duty Cycle
- Used ASME Section XI Water Environment Curve
- Three Cross Sections Analyzed

Table 3.5-4

LEAK BEFORE BREAK

Instability Flaw Length Calculation

Crack Growth Morphology

Results

Table 3.5-5

INSTABILITY FLAW LENGTH CALCULATION: LEFM

- Governing Transient: Reactor Trip
- [ ] [a,c]
- Fracture Toughness = 200 ksi$\sqrt{in}$
- Results

    LEFM Critical Length = 4.8 Inches

    Ductile Critical Length = 217 Inches (42%)

- Measurable Leakage Will Occur Well Before Critical Length Is Reached

Table 3.5-6

RECOMMENDATIONS

GRIND OUT INDICATIONS

FEEDWATER CONTROL

Table 3.5-7

APPENDIX A

Assessment of Post Stress Relief Girth Weld

Indications in Indian Point Unit 2, Steam Generator 22

ASSESSMENT OF POST STRESS RELIEF GIRTH WELD INDICATIONS IN INDIAN POINT UNIT 2, STEAM GENERATOR 22

As described in Reference 1, a girth weld repair was made in steam generator 22 of Consolidated Edison's Indian Point 2 Nuclear Power Station. This repair, to girth weld number 6, was made to restore the wall thickness to acceptable levels following grindout repairs to remove crack indications in the region of the girth weld. Following the grindout repairs, no crack indications were observable by magnetic particle inspection either prior to or following the weld repair.

After all repair welding was completed, approximately an 8 foot vertical section of the steam generator shell (around the entire outside circumference) at the girth weld region was stress relieved. The heat treatment applied an 1125 Degree F (+/- 25 Degrees F) soak temperature for approximately a 4 hour duration.

After the heat treatment process was completed and after the steam generator cooled (inside) to reasonable temperatures, the inside surface of the girth weld, along with the new weld repaired areas, were inspected by magnetic particle techniques. The inspection revealed 60 small linear indications with several clustered indications in local areas.

This report provides an assessment of the MT indications found in the post stress relief inspection. A summary of the indications is provided in Section 1. Section 2 provides an assessment of the potential causative mechanisms for the MT indications found subsequent to the stress relief operations. In Section 3, an assessment is provided relative to the potential impact of these indications on future S.G. operation. The overall conclusions from this evaluation are provided in Section 4.

1.0 Post Stress Relief Inspection Results

MT indications were found on previously ground surfaces (from the 1987 as well as the 1989 repair), at the interface of the new weld repair to the existing base metal, some of the indications were found in the deepest region of a ground area and some were found to lie on the contoured (or blended) areas. No apparent pattern of indication location (deepest part of ground area versus blended regions) could be determined. All of the indications were detectable by MT; some of the indications could be seen visually. The majority were less than 0.5 inches in length, and only 5 of the 60 were longer than 1 inch (with the longest being 2.5 inches). Zone 3 was clear of any new indications. Zone 11 had the greatest number of baseline indications at 10. One indication (1/8 inch long) in zone 1 was found in the existing base metal within approximately 1/2 inch of the edge of a blended region. The 2 indications of zone 8 were detected in the toe of the new weld metal region. Table 1 provides a summary of the number of indications found, the minimum and maximum depth of metal ground out to remove the indications, and the final shell wall thickness reduction depth at the new indications.

Disposition of the new indications revealed after the heat treatment process was identical to those found during any previous inspection process; that is, the indications were removed by grinding to a MT clear condition. All of the reported indications were removed by grinding, with the majority removed within the first 1/8 inch of metal removed.

A boat sample with an MT indication of about 1/4" length was removed for laboratory examination to assess the causative mechanism for the MT indications. The as-received surface appearance of the indication recorded on the boat sample (~ .5" wide and ~ 2.5" long) was examined by light optical microscopy (Figure 1). The indication corresponded to an area where chips of cracked surface oxide were seen (Figure 2). Sectional metallography was then conducted by successive grinding along the length of the indication to establish the depth and significance of the indication. The results of the metallographic examination conducted on several sections in the polished and etched condition confirmed that the indication is only a surface asperity with no real depth. Figure 3 shows the sectional micrograph at mid-length of the indication. The arrow corresponds to the location of the recorded indication on the surface. On this basis, it is concluded that the recorded indications may have originated from oxide cracking and/or surface distress marks on the ID surface of the girth weld. No crack was found in the boat sample even following progressive sectioning to search for cracks.

The grinding steps used to remove the post stress relief indications frequently ground to a depth up to 1/8" before re-examining by MT for crack indications. MT indications up to this depth may not be actual cracks, such that about 50% of the 60 MT indications would not be crack indications. The two MT indications found in the toe of the new weld metal were in this shallow depth category with lengths of ~0.5" and ~1.25".

2.0 Assessment of Potential Mechanisms for Post Stress Relief Crack Indications

The 2 indications at the toe of the new weld metal in zone 8 are probably the result of the heat treatment process, although, it is possible that the indications occurred during welding and were not detected by MT. During the relaxation of high residual stresses associated with welding, it is not uncommon for minor cracking to occur. If these indications are cracks that occurred due to the heat treatment process, the cracks have been identified and corrected by grinding. This type of cracking would be unique to the weld repair and introduces no concern for long term operation. Consequently, the following assessment conservatively does not distinguish between these indications in the weld area and the remaining MT indications.

Since the girth weld inspection following heat treatment resulted in the detection of linear indications away from the new weld metal region, an evaluation of the potential cause (or causes) was performed to determine the impact, if any, on the plan for return to power. The conclusion of the evaluation is that the return to power procedure in place is not impacted by the detection of these indications. This is a result of the determination that the most plausible cause of the detection of the new indications is that very tight, existing cracks were opened up by the heat treatment to the extent that the sensitivity of the MT inspection was able to differentiate them, whereas prior to the heat treatment, it was not.

The evaluation considered two basic scenarios; first, that existing, tight cracks were opened to be detectable, and second, that new cracks were initiated by the heat treatment. With the second scenario, four potential modes of failure were considered, ductile failure, brittle failure, stress corrosion cracking (SCC), and creep/fatigue damage.

The stresses induced in the girth weld during heat treatment we... assessed prior to heat treatment. The results indicate that at the time when the steady state gradient is achieved, 1) the membrane stresses are less than the expected material yield strength, 2) the linearized thru-thickness stresses would still behave elastically, and 3) the local peak stresses at grindouts may result in local plasticity. In addition, and most importantly to this evaluation, the axial and hoop stress components are compressive on the inside surface with the axial stress being the largest.

2.1 Potential for Opening of Tight Existing Cracks by the Heat Treatment Process

With the above noted state of induced stress, it is very plausible that existing cracks would open up after cooldown of the steam generator. The heat treatment stresses would cause local plastic compressive deformation in the crack region (which is at a local discontinuity). This compressive deformation on the faces of existing cracks would not be reversed when cooling occurs. Crack faces transfer a compressive stress but they cannot transfer a tensile stress from one crack face to the other. The net effect of the compressive stresses and associated plastic deformation would be a wider crack. An increase in crack length is feasible although not expected to be large. These effects increase the detectability of the crack.

2.2 Potential for New Crack Initiation by the Heat Treatment Process

The compressive stress state is also very important for three of the four modes considered for cracks potentially being initiated by the heat treatment process. These three modes are ductile failure, brittle failure, and SCC. Each of these modes of failure require tensile stress in order to occur. Since the stresses on the inside surface of the girth weld area during the heat treatment are compressive, the potential sources of tensile stresses would be either residual stresses not relaxed by prior heat treatment or stresses induced by grinding operations which could be tensile or compressive. The tensile stress would also have to occur when the material is most vulnerable, during the steady state soak of the heat treatment.

For ductile separation (ultimate failure) to occur, significant elongation of the material is required. The mostly elastic state of the girth weld region prevents this elongation from occurring. Consequently, ductile failure is not a credible scenario for crack initiation during heat treatment.

For brittle failure, the material would need to have very reduced fracture toughness properties. The girth weld material has been shown to have normal fracture toughness, including examinations using material samples removed from the girth weld area.

For stress corrosion cracking to occur, longer term steady state stresses and a corrosive environment would be required. The material is not susceptible to SCC in an air environment. Heat treatment in an air environment is a common practice including fabrication of new steam generators for which potentially higher stress states have not resulted in post heat treatment cracks.

The fourth potential mode of failure, creep/fatigue damage, is discounted on the following basis. The creep or fatigue damage or combined creep/fatigue damage from one heat treatment cycle is very small. The time of heat treatment (about 4 hours at maximum temperature) is too short to cause significant creep damage during the stress relaxation cycle and very little creep deformation could occur (stresses are also compressive on the ID, tensile on the OD). One cycle of stress causes an insignificant amount of fatigue usage. Therefore, the material would have to be at the point of incipient cracking (ready to initiate). This is not plausible since all but a few of these cracks were in grind regions. In the grind regions, especially the newly ground regions, the material with the high fatigue usage was removed and the material exposed has very low fatigue usage. The fact that new indications appeared in recently ground regions confirms that creep/fatigue damage is not a plausible cause.

2.3 Girth Weld Inspection Considerations

Magnetic particle examination sensitivity to surface or near surface defects depends on the technique, the component configuration, the degree of surface preparation and the nature of the defects.

The AC yoke, dry powder technique used on the Indian Point Unit 2 steam generator girth weld is quite adequate for detecting surface-breaking cracks because its magnetic fields are confined essentially to the surface. Therefore any surface-breaking defect would cause a leakage of the magnetic field which would be observed by the adherence of magnetic particles.

This technique's sensitivity, however, is reduced when the other factors are considered. If a defect is tight, the leakage field emanating from the surface is reduced. Therefore the force available for particle adherence is reduced. In addition, for this case, the component is vertical which means that the magnetic particle mobility is determined by both magnetic fields and gravity. This factor combined with weak leakage fields significantly affects the ability to detect tight cracks.

The AC yoke, dry powder technique is typically not adequate for near surface, non-surface breaking defects because the penetration of the magnetic field is limited to only a skin depth.

This reduced sensitivity can explain some of the discrepancies between the MT clear results obtained prior to stress relief and the MT indications discovered after the stress relief.

Another plausible cause of the after stress relief indications could be due to oxide particles or oxide cracking which may trap the magnetic particles and cause linear type MT indications.

2.4 Conclusions

Based on the above assessment, the most likely mechanism for the crack indications found subsequent to the stress relief process is that the compressive stresses induced by the heat treatment led to opening of existing, tight cracks. These small and tight cracks were not identifiable by the "state of the art" MT inspection techniques. The primary inspection method used dry power with AC magnetization. Several ground out areas were MT tested with dry powder and DC magnetization with no new indications detected.

Alternate mechanisms assessed for potential crack initiation during the stress relief process included ductile failure, brittle failure, SCC and creep/fatigue damage. None of these potential mechanisms appears to be a credible scenario for crack initiation.

3.0 Assessment of Impact on SG Operation

This section addresses the potential impact of the identified post stress relief crack indications on SG operation. Since the crack indications are attributable to small, tight cracks not identifiable by the MT inspection process, the influence of this conclusion on crack initiation and growth over both the last fuel cycle and the operating period to the next inspection are assessed in this section.

During the previous outage in 1987, it is expected that not all of the cracks were completely removed even though they were MT clear within the sensitivity of the "state of the art" inspection technique. Some small, very tight cracks remained and could be responsible for many of the "new" and deeper indications found during this outage. The 1989 crack indications in previously un-ground regions could be new initiations due to prior accumulated fatigue usage. However, the new indications found in previously ground regions probably were not initiated in the last operating cycle.

The transients experienced and the time at hot standby during the last fuel cycle were average compared to the total duty cycle. Newly accumulated fatigue usage should have been no larger than any prior fuel cycle and many cycles were required to initiate the cracking discovered in 1987. Measures have also been taken since 1987, and previously, to improve water chemistry and oxygen levels. Both actions should have reduced the fatigue usage accumulated over the last fuel cycle. It is therefore reasonable to expect that the largest depth cracks found in the current outage resulted from previously present but undetectable small, tight cracks.

Assuming that the last fuel cycle and the heat treatment have led to the detection of essentially all the cracks in steam generator 22, the evaluation emphasis should be placed on the other steam generators. In these units, the maximum depth of grind required to remove the current outage indications was 0.34 inch, with an average of less than 0.21 inch. This crack growth was likely a continuation of prior growth and the cracks became more detectable because of the 14.4 months of operation. The next cycle of operation (approximately 16 months) should not lead to the crack growth experienced in the last cycle for several reasons:

1. The downcomer resistance plates have been removed which will result in lower thermally induced stresses. Lower stresses and significantly reduced load cycles lead to lower crack growth rates.

2. Main feedwater chemistry and oxygen levels continue to receive attention directed toward further improvements. Better chemistry and oxygen in the main feedwater means lower crack growth rates.

3. A modification was installed which delays closure of the main feedwater flow bypass regulatory valves in the event of a reactor trip. Implementation of this modification during operation provides hot main feedwater flow to the steam generators following a trip. Due to a concern stemming from false SI signals, the transient is being evaluated analytically. Assuming positive results from the evaluation, the modification will be implemented.

4. Two taps are being installed on the 12" Condensate Storage Tank (CST) discharge and 6" return lines. A deoxygenation skid will be connected to these taps which can provide water at the discharge with less than 10 PPB oxygen. In this manner the oxygen concentration in the CST will be maintained less than 10 PPB.

The potential for cracks being left behind has been minimized by the thorough inspections and crack removal in the last two cycles. The cracks are being removed in a shorter time period than it takes to initiate new cracks in the ground material with low cumulative fatigue damage. In addition, the above mitigating actions lengthen the time required for new cracks to be initiated, both in un-ground regions and ground regions.

Even if it is conservatively assumed that the maximum crack depth of 0.95 inch that occurred in steam generator 22 were to repeat itself, it has been shown (Reference 1) that a factor of 2 exists on critical flaw size. A thru-wall leak would occur before the shell integrity would be compromised and therefore there is no safety concern. The mitigating actions being implemented in the current cycle will have positive effects to further reduce crack initiation and growth.

As noted in Reference 1, the next girth weld inspection will be performed during a shutdown at approximately mid-cycle. The shorter inspection interval compared to the prior operating period between inspections together with the mitigating actions can be expected to result in both lower crack initiation and growth rates.

4.0 Overall Conclusions

The overall conclusions from this assessment are:

1. The boat sample taken to include a MT indication was found to be free of cracks. This result indicates that the MT indications may include surface effects with no real depth. About 50% of the 60 MT indications may therefore not be actual crack indications.

2. The most likely mechanism for the detection of "new" cracks following the stress relief in steam generator 22 is the opening up of existing small and tight, undetectable cracks as a consequence of plastic compressive deformation on the crack faces during the heat treatment process.

3. No credible mechanism has been identified that would lead to an expectation that the cracks were initiated by the heat treatment process.

4. The return to power actions being taken, as described in Reference 1 and this letter, are suff[illegible]nt to mitigate future crack initiation and/or crack [illegible]th and thereby assure structural integrity of the steam generators.

References

1. WCAP-12293, Indian Point Unit 2 Steam Generator Girth Weld/ Feedwater Nozzles Report - Spring 1989 Outage, Consolidated Edison of New York, June 1989.

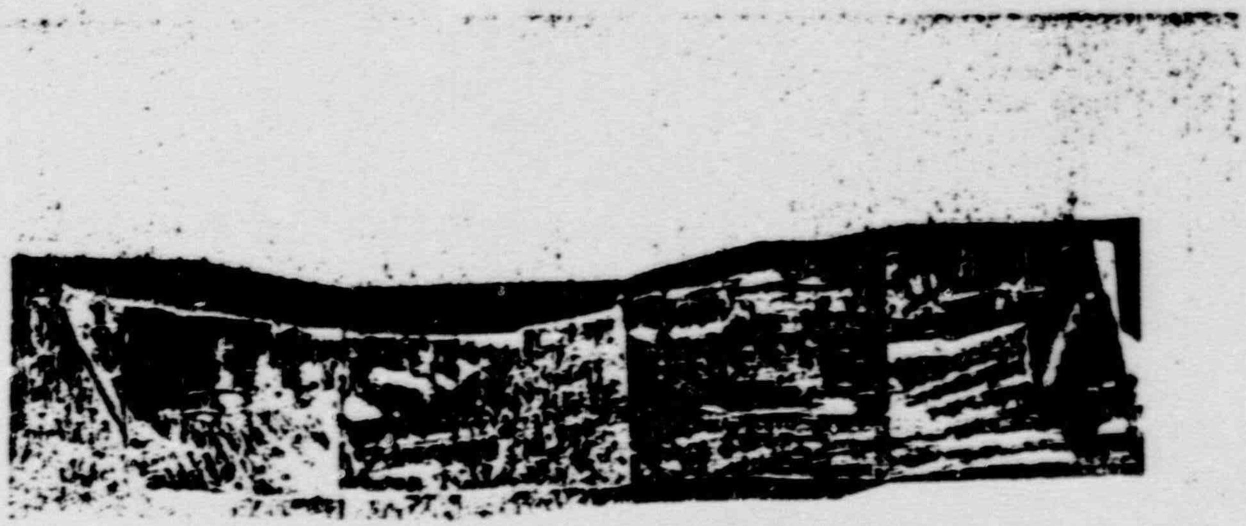


FIGURE 1 As received appearance of the boat sample showing the location of the surface indication.

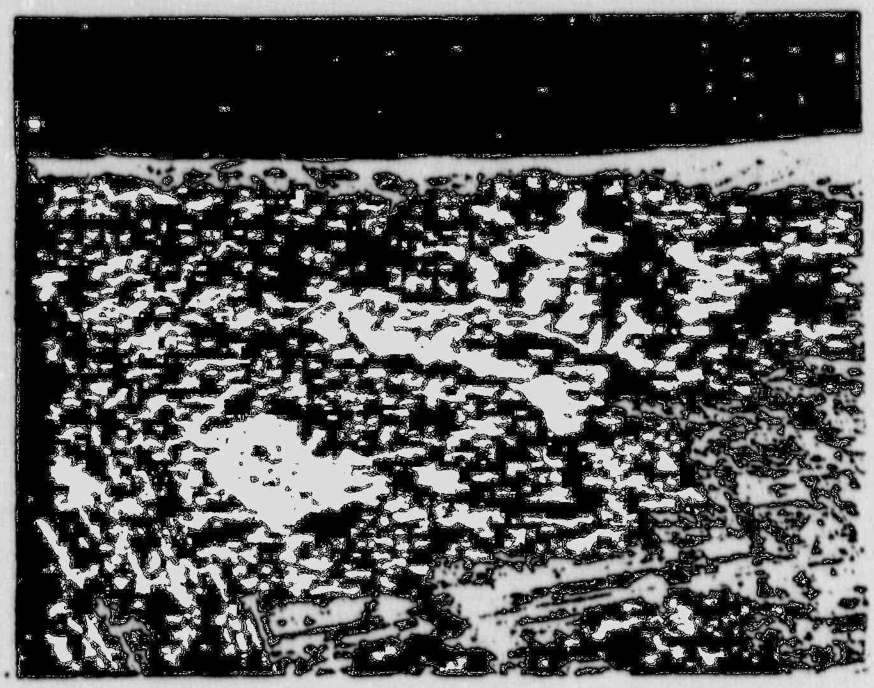


FIGURE 2 Close-up view of the boat surface at the recorded indication.

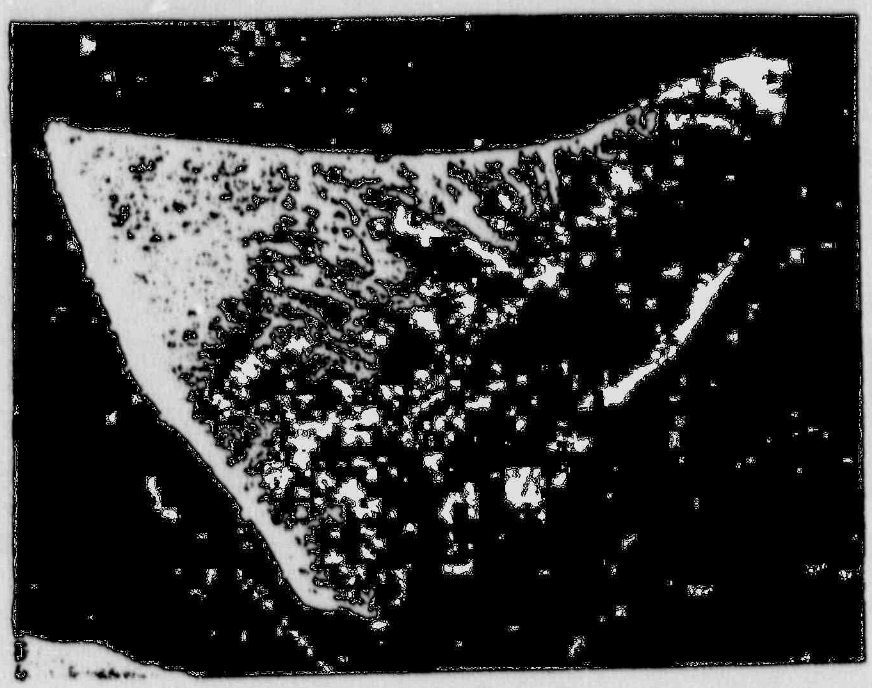


FIGURE 3 Metallography results on a boat section through the mid-length of the indication.

TABLE 1

STEAM GENERATOR 22 - SUMMARY OF INDICATIONS AFTER STRESS RELIEF

ZONE	NO. OF INDICATIONS	MIN/MAX DEPTH OF METAL REMOVED	FINAL DEPTH - WALL THICKNESS REDUCTION NOTE 2
1	8	Surface/0.297 (Note 1)	0.407
2	3	Surface/0.237 (Note 1)	0.407
3	0		
4	4	< 0.258/0.258	0.727
5	8	0.014/0.093	0.532
6	6	0.186/0.304	0.657
7	4	0.086/0.142	0.724
8	2	0.068/0.125	0.125
9	3	0.086/0.244	0.594
10	2	0.250/0.322	0.687
11	10	0.031/0.370	0.625
12	9	0.031/0.312	0.625
	60		

Notes

1. "Surface" means that indication(s) were removed with light buffing from using a flapper wheel (estimated depth < 0.005 inches).
2. Cumulative depth of wall thickness reduction at new indication location(s).