MAR 1 9 1982

MEMORANDUM FOR: Tolbert Young, Jr., Chief, Reactor Operations Projects Section 2

FROM: Roger J. Mattson, Director, Division of Systems Integration

SUBJECT: CLARIFICATION OF A STEP IN OUR PRELIMINARY EVALUATION OF OPERATOR ACTION FOR GINNA SG TUBE RUPTURE EVENT

Reference: Memorandum dated March 2, 1982, from Tolbert Young, Jr., to R. Mattson

The remarks presented in the January 28th memo compared the actual operator actions to the actions recommended in the Westinghouse generic guidelines. The guidelines recommend that the operator depressurize the reactor coolant system to the ruptured steam generator pressure as soon as the initial cooling stage is over (i.e., the core exit temperature is about 50°F below the ruptured SG saturation temperature). Previous background information accompanying this recommendation indicates that Westinghouse has been aware of the possibility of upper head voiding. The background information for the generic guideline, meant to be used for operator training, states:

> "If no RCP is running, voiding in the upper head may occur (depending on the ruptured steam generator pressure) during depressurization of the primary to the ruptured steam generator pressure. This will result in a rapidly increasing pressurizer level as water displaced from the upper head, in addition to excess safety injection flow, replaces vented steam in the pressurizer. In addition, depressurization of the primary will be slowed. Consequently, pressurizer level may approach off-scale high before primary pressure decreases to the ruptured steam generator pressure. Pressurizer level must be monitored to prevent filling the pressurizer."

The Ginna event progressed as predicted in the text above, except for the stuck open PORV, which resulted in completely filling the pressurizer and RCS pressure decrease about 100 psi below the ruptured SG pressure.

As mentioned in the memo, the SG B pressure was lower than expected by Westinghouse. This lower pressure appears to be because the operators started to decrease the secondary pressure before the ruptured SG B was isolated. We would expect that if the guidelines had been strictly followed (Reminder: not the actual Ginna procedures), the pressure in SG B would have stabilized to a value above 900 psi (in most other Westinghouse plants, well above 1000 psi). However, we should recognize that tripping the reactor coolant pump may leave the upper head sufficiently hot that flashing would take would take place at event higher pressures.

D/9

CONTACT: J. Laaksonen, X28967

OFFICE						
SURNAME						
DATE						

The Westinghouse generic guidelines are still under our review and, in a set of questions sent to Westinghouse Owners Group, we have asked that the possibility of flashing in the reactor vessel upper head during the depressurization be further considered. We have not ruled out the possibility that further evaluation by Westinghouse and the staff may confirm the viability of this portion of the generic guideline. If this would be the case, a note mentioning the possibility of flashing may be added.

We appreciate the comment you have made and agree that the step you have proposed may reduce the potential for lifting the steam safety valves, at the same time limiting the amount of flashing in the reactor vessel upper head. However, the principal goal of depressurization is to terminate the primary-to-secondary leak to prevent flooding of the steam lines (which is likely to have taken place in Ginna). The importance of this goal has to be taken into account when considering the risks related to a steam bubble in the upper head (which will disappear when the RCP is restarted).

The reactor vessel upper head voiding has been seen also during other events and discussions with the licensees on the subject are underway. For your information we enclose a generic letter sent to all licensees of operating PWR's.

If you have any questions about our response to your memo or you would like to discuss this subject further with us, please do not hesitate to call me or members of my staff.

Original Signed by
Roger J. Mattson
Roger J. Mattson, Director
Division of Systems Integration

Enclosure:
As stated

Distribution
Docket File
RSB R/F
E. Case
H. Denton
PPAS
D. Eisenhut
S. Hanauer
R. Vollmer
H. Thompson
P. Check
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J. Laaksonen
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R. Mattson
RSB Plant File
J. Laaksonen R/F
B. Capra (82-101)
S. Cavanaugh (82-101)

OFFICE	DSI:RSB	DSI:RSB	DSI:RSB	DSI:AD:RS	DSI:DIR		
SURNAME	JLaaksonen/bg	GMazetis	BSheron	TSpeis	RMattson		
DATE	3/18/82	3/19/82	3/19/82	3/19/82	3/19/82		

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

MAY 5 1981

TO ALL LICENSEES OF OPERATING PRESSURIZED WATER NUCLEAR POWER REACTORS AND APPLICANTS FOR OPERATING LICENSES (EXCEPT FOR ST. LUCIE, UNIT NO. 1)

Gentlemen:

SUBJECT: NATURAL CIRCULATION COOLDOWN
(Generic Letter No. 81-21)

On June 11, 1980, the St. Lucie Plant, Unit No. 1, was forced to cool down on natural circulation as a result of a component cooling water malfunction. During the cooldown process, abnormally rapid increases in pressurizer level were observed. Subsequent analyses have confirmed that these abnormal level increases were produced by flashing of liquid in the upper head of the reactor vessel, forcing water out of the vessel and into the pressurizer. A more complete description of the event and circumstances involved is provided in the enclosure which includes a letter sent to the PWR NSSS vendors soliciting their opinions and comments on the significance of the event and phenomenon in general.

Based on our review of the event to date, we believe that core cooling was never lost during the St. Lucie, Unit No. 1 event. That specific event does not constitute a direct safety concern. We have, however, identified two areas of concern applicable to all pressurized water reactors requiring prompt action:

1. <u>The Unacceptability of Vessel Voiding During Anticipated Cooldown Conditions (Natural Circulation Due to Loss of Offsite Power, Loss of Pumps, etc.)</u>

   Cooldown with a significant steam void in the vessel requires controlling a "two pressurizer" system, which is an undesirable challenge to the operator. In fact, we are not aware of any training facilities (simulators) today which would allow an operator "hands on" experience in practicing such control. Moreover, it is our opinion that any significant vessel voiding produced during controlled cooldown conditions increases the susceptibility of the plant to more serious accidents. For these reasons reactor vessel voiding during controlled natural circulation cooldowns should be avoided.

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As described in the enclosure, vessel voiding at St. Lucie, Unit No. 1, was caused by the operator reducing system pressure such that the corresponding saturation temperature dropped to the temperature of the relatively stagnant fluid in the reactor vessel upper head. Presently, primary system cooldown rates are based on vessel structural integrity considerations and do not explicitly consider avoiding production of significant steam voids in the vessel. Moreover, cooldown rates are based on fluid temperatures measured in the primary piping. As the St. Lucie Unit No. 1 event has shown, these measured temperatures can in fact be on the order of 100 degrees Fahrenheit or more lower than the upper head fluid temperature, and, therefore, not indicative of the saturation pressure of all fluid in the primary system.

Under conditions which require cooldown on natural circulation and when rapid depressurization is not necessary there may be a number of ways to avoid reactor vessel voiding. For example, a low cooldown rate can be specified, coupled with "holding" the plant at intermediate conditions to allow the fluid in the upper vessel to equilibrate with the rest of the primary system. However, avoidance of vessel voiding by lower primary system cooldown rates can increase the time required to achieve shutdown cooling entry conditions and thus increase the time auxiliary feedwater is depended upon to remove decay heat (specifically, for the loss-of-offsite power case). Thus, supplies of condensate-grade auxiliary feedwater must be considered if cooldown times are extended.

2. Failure of the Operator to Have Prior Knowledge and Training for This Event

The cause of initial surges in pressurizer level at St. Lucie, Unit No. 1, was not immediately recognized or understood by the operator. We attribute this to the fact that long-term natural circulation cooldown under the specific circumstances of the event was never explicitly analysed by the NSSS vendor from the standpoint of trying to recognize a phenomenon such as that which occurred at St. Lucie, Unit No. 1. In the St. Lucie event, the operator ultimately recognized the cause of the level surges and was able to maintain control of the plant. Our concern, however, is the possibility of an operator taking incorrect action in an effort to correct for an unknown event or unrecognized phenomena.

We believe that proper procedures and training can provide the necessary guidance to the operators both to avoid reactor vessel voiding as well as recognize it when, and if, it occurs during controlled natural circulation cooldown. We are not sure if such procedures and training are in place at pressurized water reactor facilities.

Consequently, we request that you promptly review your current plant operations in light of the St. Lucie, Unit No. 1 event and the discussions above and implement, as necessary, procedures and training which will enable operators to avoid (if possible), recognize and properly react to reactor vessel voiding during natural circulation cooldown.

We conclude that the actions described above should be completed as soon as they reasonably can be (i.e., within 6 months for operating reactors). In addition, so that we may determine whether your license should be amended to incorporate these actions as requirements, licensees of operating pressurized water reactors are requested, pursuant to §50.54(f), to furnish, within 6 months of receipt of this letter, an assessment of your facility procedures and training program with respect to the matters described above. Your assessment should include:

1. a demonstration (e.g. analysis and/or test) that controlled natural circulation cooldown from operating conditions to cold shutdown conditions, conducted in accordance with your procedure, should not result in reactor vessel voiding;

2. verification that supplies of condensate-grade auxiliary feedwater are sufficient to support your cooldown method; and

3. a description of your training program and the provisions of your procedures (e.g. limited cooldown rate, response to rapid change in pressurizer level) that deal with prevention or mitigation of reactor vessel voiding.

Applicants for operating licensees are requested to implement the subject procedures and training and provide the requested assessment within 6 months of receipt of this letter or 4 months prior to the staff's scheduled issuance of its operating license Safety Evaluation Report, whichever is later.

Please refer to this letter in your response.

This request for information was approved by OMB under a blanket clearance number R0072 which expires December 31, 1981. Comments on burden and duplication may be directed to the Office of Management and Budget, Reports Management, Room 3208, New Executive Office Building, Washington, D.C. 20503.

Sincerely,

Darrell G. Eisenhut

Darrell G. Eisenhut, Director
Division of Licensing
Office of Nuclear Reactor Regulation

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

Enclosure 1

AUG 12 1980

Letter sent to PWR NSSS Vendors:
Westinghouse, Combustion Engineering and
Babcock and Wilcox

Dear Mr.

SUBJECT: VOID FORMATION IN VESSEL HEAD DURING ST. LUCIE NATURAL CIRCULATION COOLDOWN EVENT OF 6/11/80

On June 11, 1980, the St. Lucie reactor was shutdown due to a loss of component cooling water to the reactor coolant pump seals. This also required shutdown of the reactor coolant pumps and cooldown was accomplished by natural circulation.

At approximately 4 hours into the event, charging flow, which was initially being divided between the cold legs and the auxiliary pressurizer spray, was diverted entirely to the auxiliary spray to enhance the depressurization and reduce the system pressure on the pump seals. At this time, abnormally rapid increases in pressurizer level were observed which could not be explained by the charging flow rate alone. Detailed evaluation and follow-up analyses by the licensee and NSSS supplier have indicated that a steam void was probably formed in the upper head region of the reactor vessel and displaced water from the vessel into the pressurizer.

Continued alternating realignment of charging flow between the cold legs and auxiliary spray line [illegible]uced a "saw-tooth" pressurizer level behavior. Relevant information and [illegible]a available to the staff to date are provided in the enclosure.

It has been postulated that the steam void in the upper vessel was produced when the system pressure dropped below the saturation pressure corresponding to the temperature of the fluid in the upper head. Because the measured hot and cold leg temperatures at the time of voiding were highly subcooled (~200°F), it appears that the fluid in the upper head was much hotter, relativel[illegible] stagnant, and in poor communication with the fluid exiting the core and in the upper plenum. In addition, stored heat in the upper head structures most likely contributed to the voiding.

Because of the unexpected occurrence of the void, the failure of the operators to immediately recognize the void formation and take corrective action, and the question of whether such void formation is properly accounted for in safety

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3pp

analyses (Chapter 15), we have sent a list [redacted]ting our concerns to the licensee. These questions [redacted] the enclosure for your information.

We are presently evaluating the need to purs[redacted]ically with all PWR licensees. Prior to taking any defi[redacted]er, we are soliciting your technical opinion and advise [redacted]ntial for void formation under similar circumstances in [redacted] you. Specifically, we need to know if you can just [redacted] phenomenon cannot occur in NSSS's designed by you (or ca[redacted]h phenomena can be properly predicted by your transient [redacted]nd if it can occur, is properly accounted for in operatin[redacted] cooldown rates), operator guidelines, and operator tr[redacted]he simulator)

The urgency of this matter requires you advi[redacted]n (15) working days after receipt of this letter wh[redacted]l information submittal by you on the subject would preclu[redacted]editiously pursue this issue generically with your cust[redacted]

Paul S. [redacted]irector for
Plant [redacted]
Division [redacted]tion
Office of [redacted]egulation

GINNA STATION
B-STEAM GENERATOR
NRC MEETING
MARCH 23, 1982

AGENDA

- INTRODUCTION
- INSPECTION AND EXAMINATION RESULTS
- DAMAGE MECHANISM EVALUATION
- RECOVERY PROGRAM
- TECHNICAL BASIS FOR REPAIRS
- PLANT SCHEDULE
- CONCLUSION

B/10

GINNA STATION
B-STEAM GENERATOR
NRC MEETING
MARCH 23, 1982

OBJECTIVES

- o DETERMINE FULL EXTENT OF DEFECTS AND LOOSE PARTS
- o DETERMINE FAILURE MECHANISM(S)
- o RESTORE STEAM GENERATOR TO A CONDITION WHICH IS SAFE TO OPERATE MAINTAINING RADIATION EXPOSURES AS LOW AS REASONABLY ACHIEVABLE
- o OBTAIN NRC CONCURRENCE FOR RETURN TO POWER

GINNA STATION
B-STEAM GENERATOR
NRC MEETING
MARCH 23, 1982

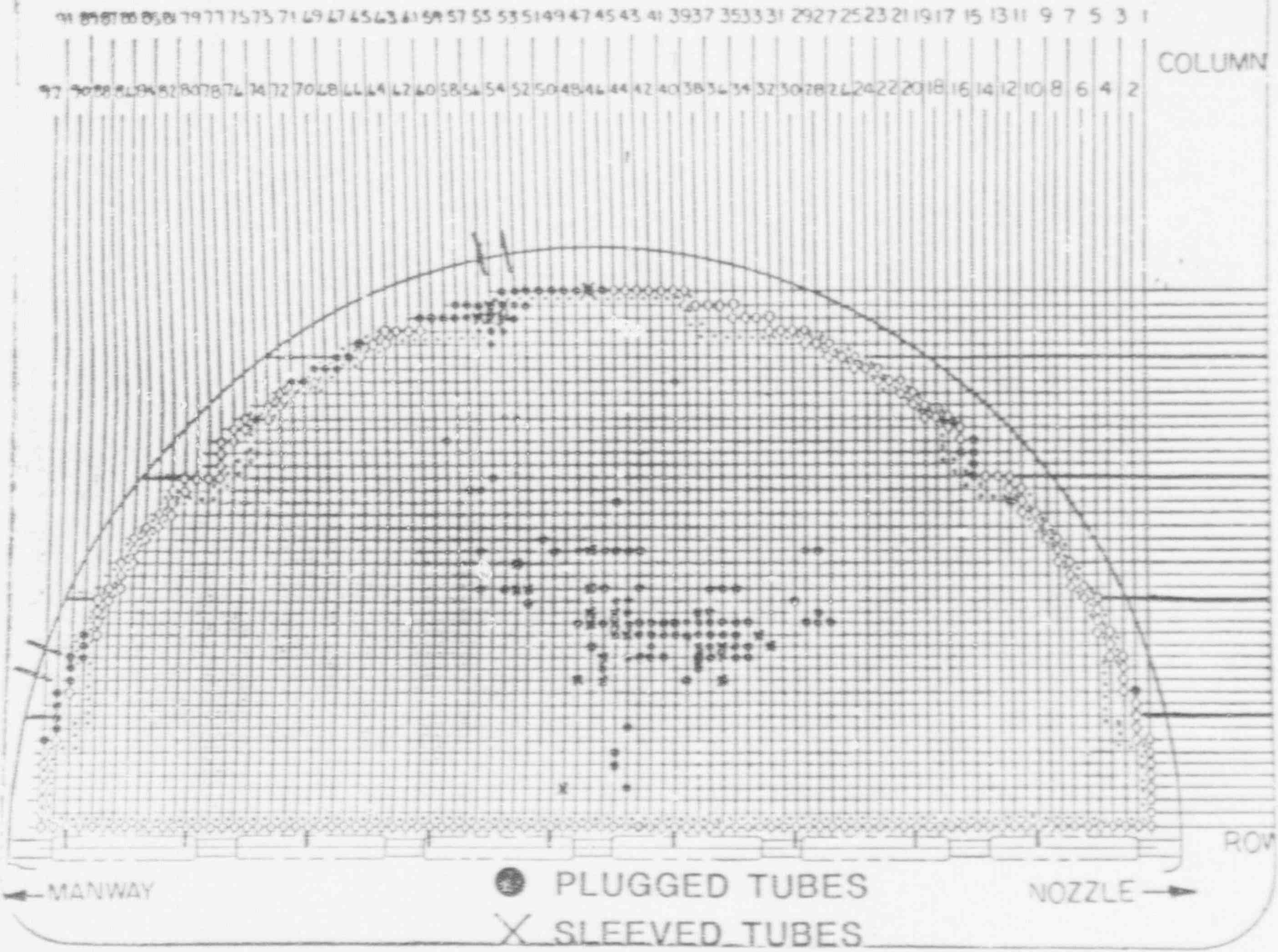
PURPOSE OF MEETING

- TO REVIEW RESULTS OF INSPECTIONS TO DATE

- TO OBTAIN CONCURRENCE WITH STEAM GENERATOR PROGRAM CONCEPTS

- TO OBTAIN APPROVAL FOR REMOVAL OF STEAM GENERATOR TUBE SECTIONS

RG&E Steam Generator



GINNA STATION
B-STEAM GENERATOR
NRC MEETING
MARCH 23, 1982

NSARB/NRC REVIEWS

- concurrence with program concepts

  NSARB - 2/26

  NRC - 3/1

- approval of removal of metallurgical samples

  NSARB - 2/26

  NRC - 3/1

- approval of repair program

  NSARB - 3/16

  NRC - 3/23

- approval of return to power

  NSARB - mid April

  NRC - late April

GINNA STATION
B-STEAM GENERATOR
NRC MEETING
MARCH 23, 1982

INSPECTION UPDATE
NO. 4 WEDGE AREA

- R45C54 51" [illegible]

  -missing and severed at first support plate

- R44C54

  -severed at top of tubesheet

- R44C55

  -severed at top of tubesheet

  -partially severed at first support plate

- R43C55

  -severed at top of tubesheet

- R44C56

  -missing and severed at first support plate

- R44C57 51"

  -missing and severed at first support plate

GINNA STATION
B-STEAM GENERATOR
NRC MEETING
MARCH 23, 1982

METALLURGICAL EXAMINATION

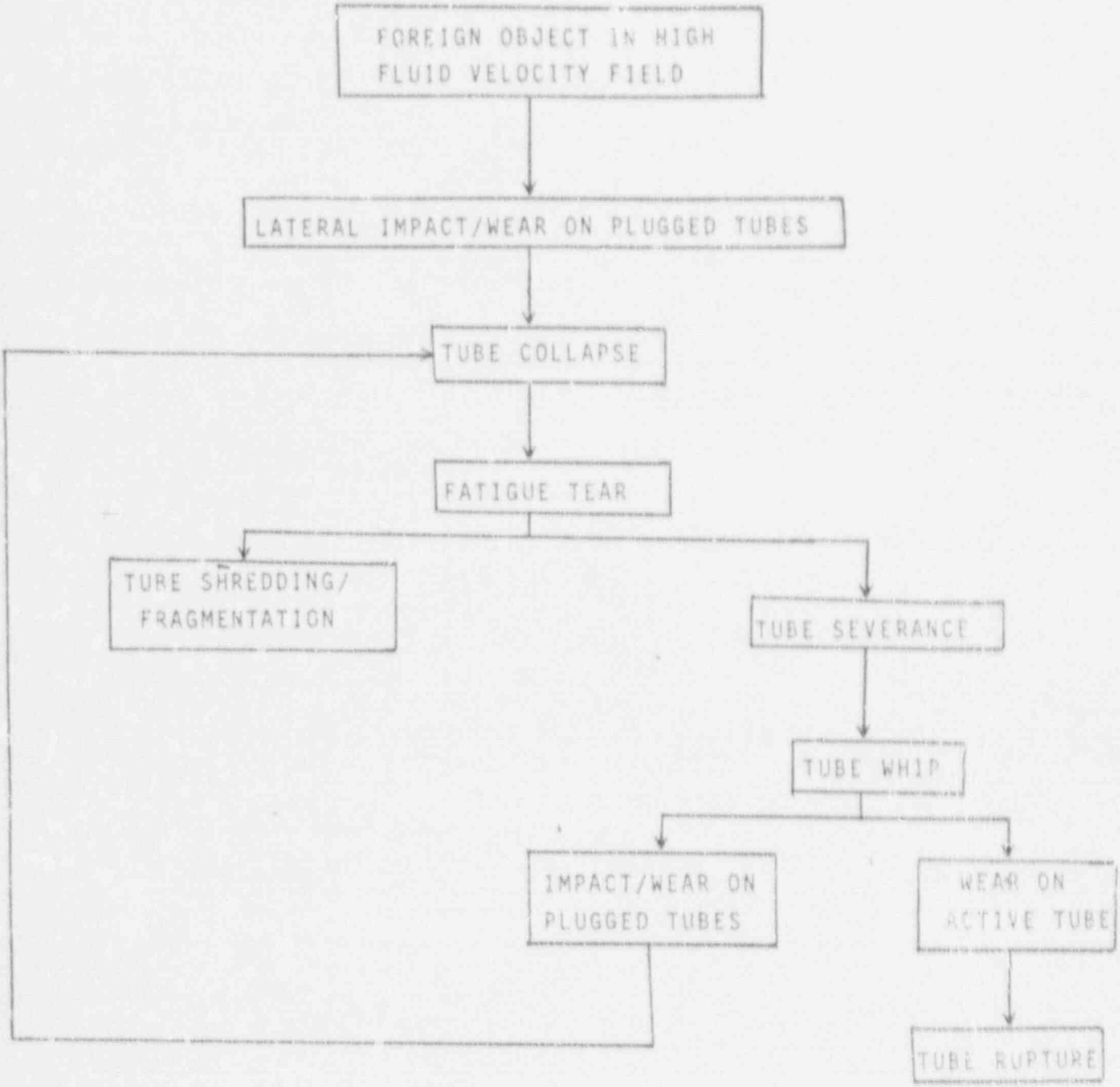
- site photography
- Westinghouse R&D laboratories
- model for wear orientation comparisons
- photography at 90° increments
- radiography at 45° increments
- transverse cross sections of column 55 tubes
  - -R42C55 - 2.5" and 4" from upper end
  - -R43C55 - 2.5" and 4" from upper end
  - -R44C55 - 2.5", 4" and 8" from upper end
  - -SEM and standard photomicrographs

GINNA STATION
B-STEAM GENERATOR
NRC MEETING
MARCH 23, 1982

LABORATORY EXAMINATION REMOVED TUBING

- WEAR SURFACES
- PRIMARILY RUBBING WEAR CIRCUMFERENTIAL DIRECTION
- NO EVIDENCE OF CORROSION INVOLVEMENT
- EVIDENCE OF SURFACE COLD WORKING
- FATIGUE STRIATION ON FRACTURE SURFACE
- TENSILE OVERLOAD BURST TUBE FAILURE SURFACE

R. E. GINNA S/G B - POSTULATED TUBE RUPTURE MECHANISM



MECHANISM EVALUATION PROGRAM

- INVESTIGATION OF VARIOUS INFLUENCES
  - MECHANICAL LATERAL LOADS
  - GROSS FLUID LOADS
  - AXIAL LOADS
  - LOCAL FLUID LOADS
- HISTORICAL INFORMATION REVIEW
- INITIAL PERIMETER TUBE INVESTIGATION
- LABORATORY EXAMINATION OF REMOVED TUBE SECTIONS
- MODEL TESTING
- LABORATORY COLLAPSE AND FATIGUE TESTING
- FIELD TESTING AND EXAMINATION

LATERAL LOADS

- EXTERNAL PRESSURE
- TUBE OVALITY
- VARYING LEVELS OF CONCENTRATED LOADS
- VARYING LEVELS OF TUBE WALL THICKNESS
- AXIAL LOAD AFFECT

GROSS FLUID LOADS

- FLUID ELASTIC INTERACTION ANALYSIS

    FLOW VELOCITIES

    TUBE CROSS SECTION

    FLUID ELASTIC STABILITY

    VORTEX SHEDDING

    CROSS FLOW

- EFFECT OF TUBE REMOVAL ON FLUID FLOW FIELD

AXIAL LOADS

- STRUCTURAL EVALUATION

  TUBE-TO-SHELL MISMATCH

  TUBE-TO-TUBE MISMATCH

  MISALIGNMENT

  TUBESHEET-SUPPORT PLATE MISMATCH

  TUBESHEET ROTATION

  STRESS CONCENTRATION

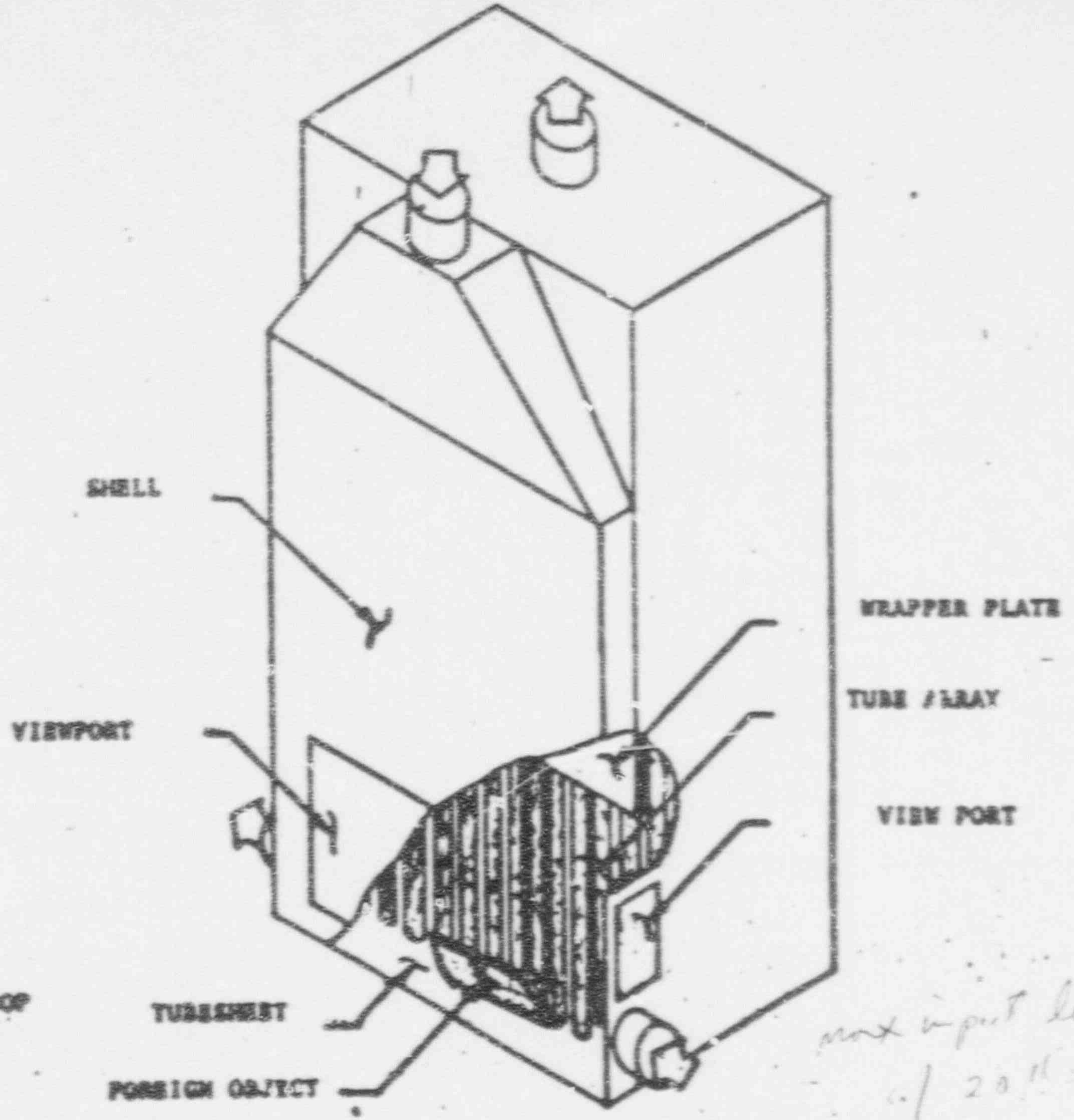
- U-BEND WITH REMOVED SECTION

GINNA STATION
B-STEAM GENERATOR
NRC MEETING
MARCH 23, 1982

LABORATORY EXAMINATION REMOVED TUBING

- WEAR SURFACES
- PRIMARILY RUBBING WEAR CIRCUMFERENTIAL DIRECTION
- NO EVIDENCE OF CORROSION INVOLVEMENT
- EVIDENCE OF SURFACE COLD WORKING
- FATIGUE STRIATION ON FRACTURE SURFACE
- TENSILE OVERLOAD BURST TUBE FAILURE SURFACE

BUNDLE INLET FLOW MODEL



COLD FLOW TEST LOOP
ENGINEERING TEST
FACILITY
TAMPA, FLORIDA
KLM-2/82

max input loads
w/ 20"

LABORATORY TESTING

- COLLAPSE TESTING

  EXTERNAL PRESSURE

  LATERAL LOADS

  AXIAL LOAD

- FATIGUE TESTING

  AMPLITUDES

  GEOMETRY

  BOUNDARY CONDITION

  AXIAL LOAD

GINNA STATION
B-STEAM GENERATOR
NRC MEETING
MARCH 23, 1982

CORRECTIVE ACTIONS

- o eddy current examination
- o video inspections
- o obtain metallurgical samples
- o remove structurally degraded tube sections
- o restore preventatively plugged tubes to service
- o remove foreign objects and tubing fragments
- o eddy current examine tubes adjacent to repairs
- o secondary side video inspection following repairs
- o primary and secondary hydrostatic tests
- o metal impact monitoring system

GINNA STATION
B-STEAM GENERATOR
NRC MEETING
MARCH 23, 1982

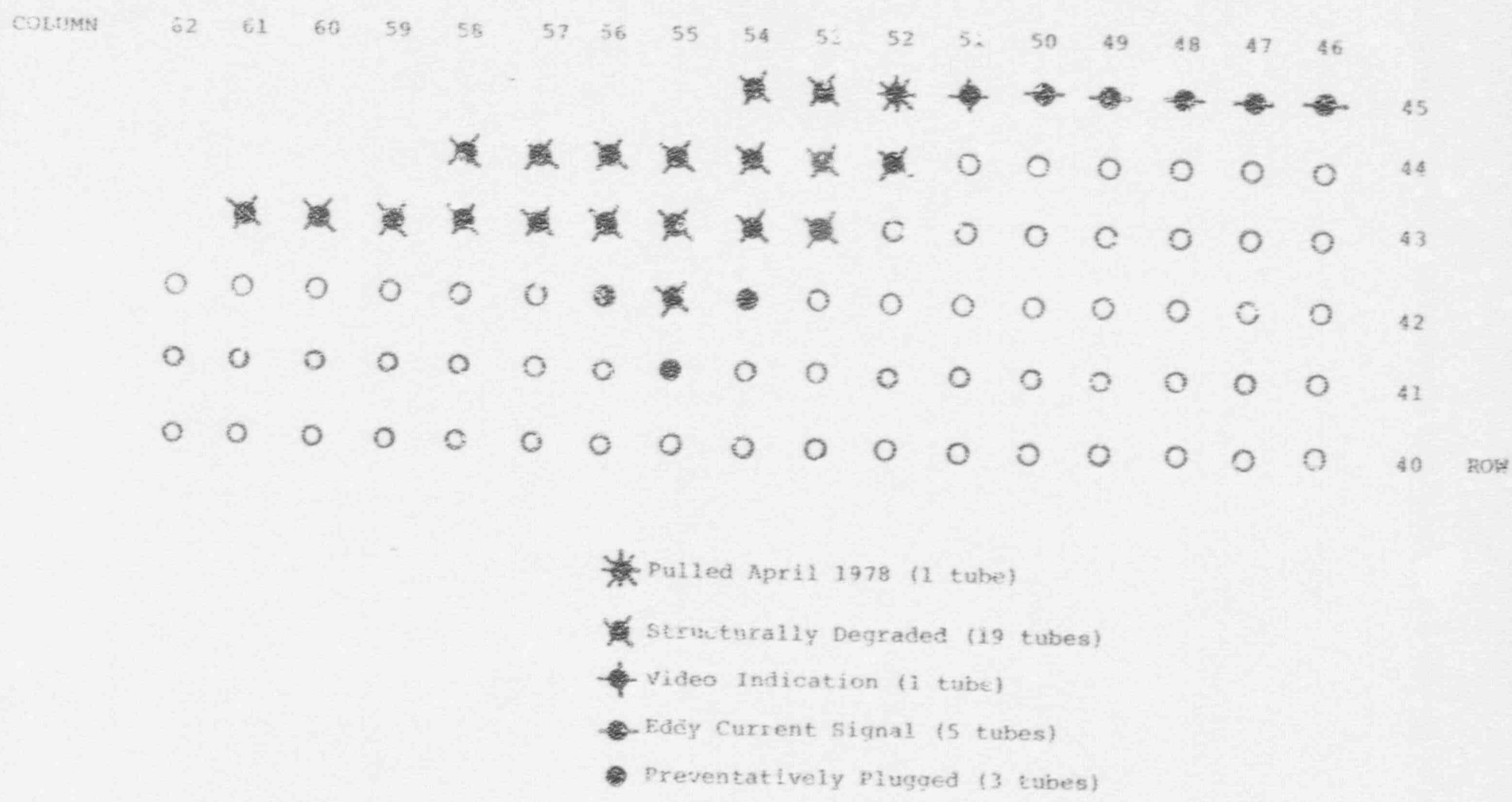
REPAIR OPTIONS

- EDM cutting process
- mechanical cutters
- hydraulic tube removal system
- loose parts retrieval equipment
- remove from tubesheet end
- additional shell penetrations
- proven repair techniques

CINNA STATION

B-STEAM GENERATOR

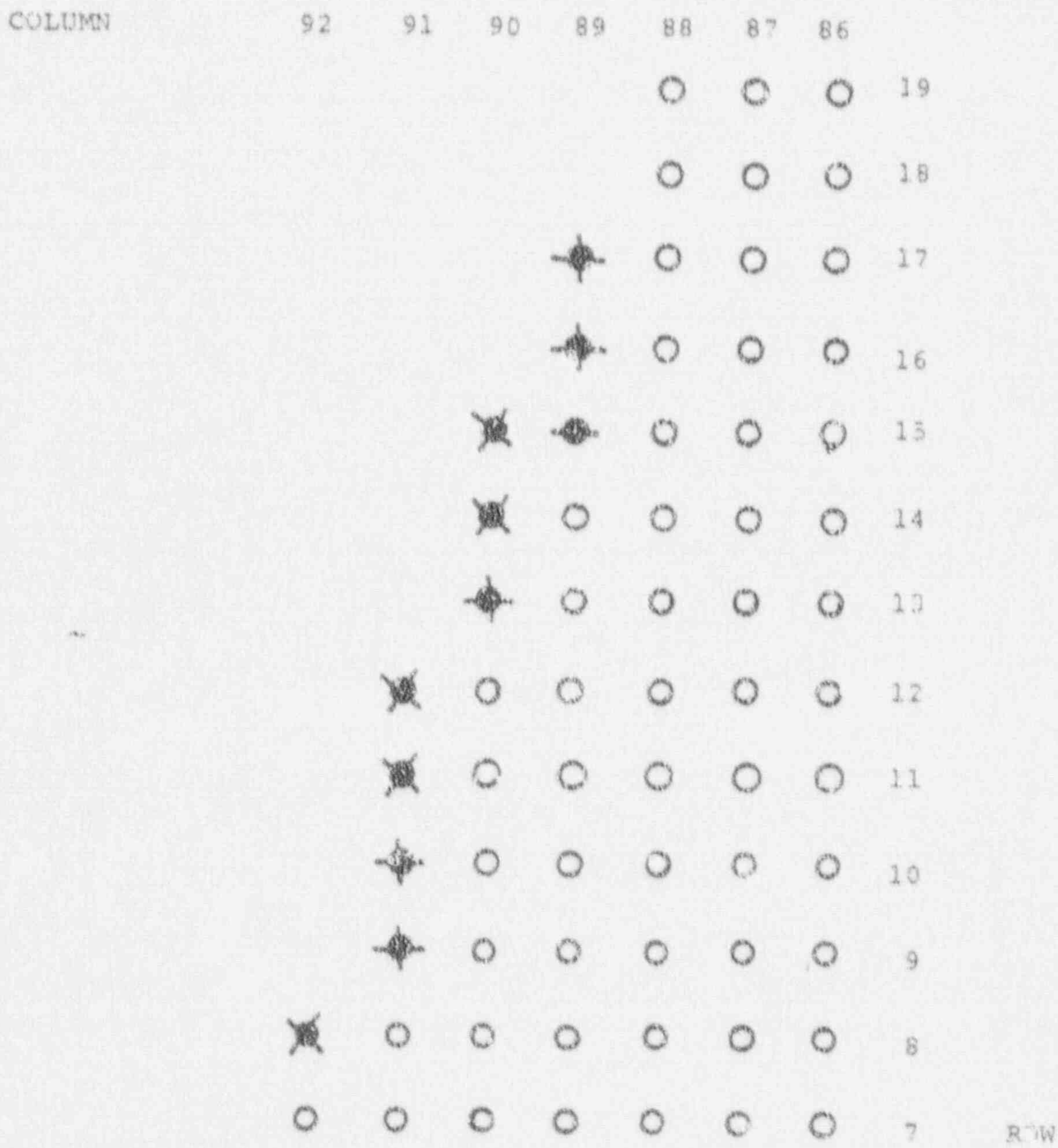
NO. 4 WEDGE AREA



GINNA STATION

B-STEAM GENERATOR

NO. 6 WEDGE AREA



Structurally Degraded (5 tubes)

Video OD Indication (5 tubes)

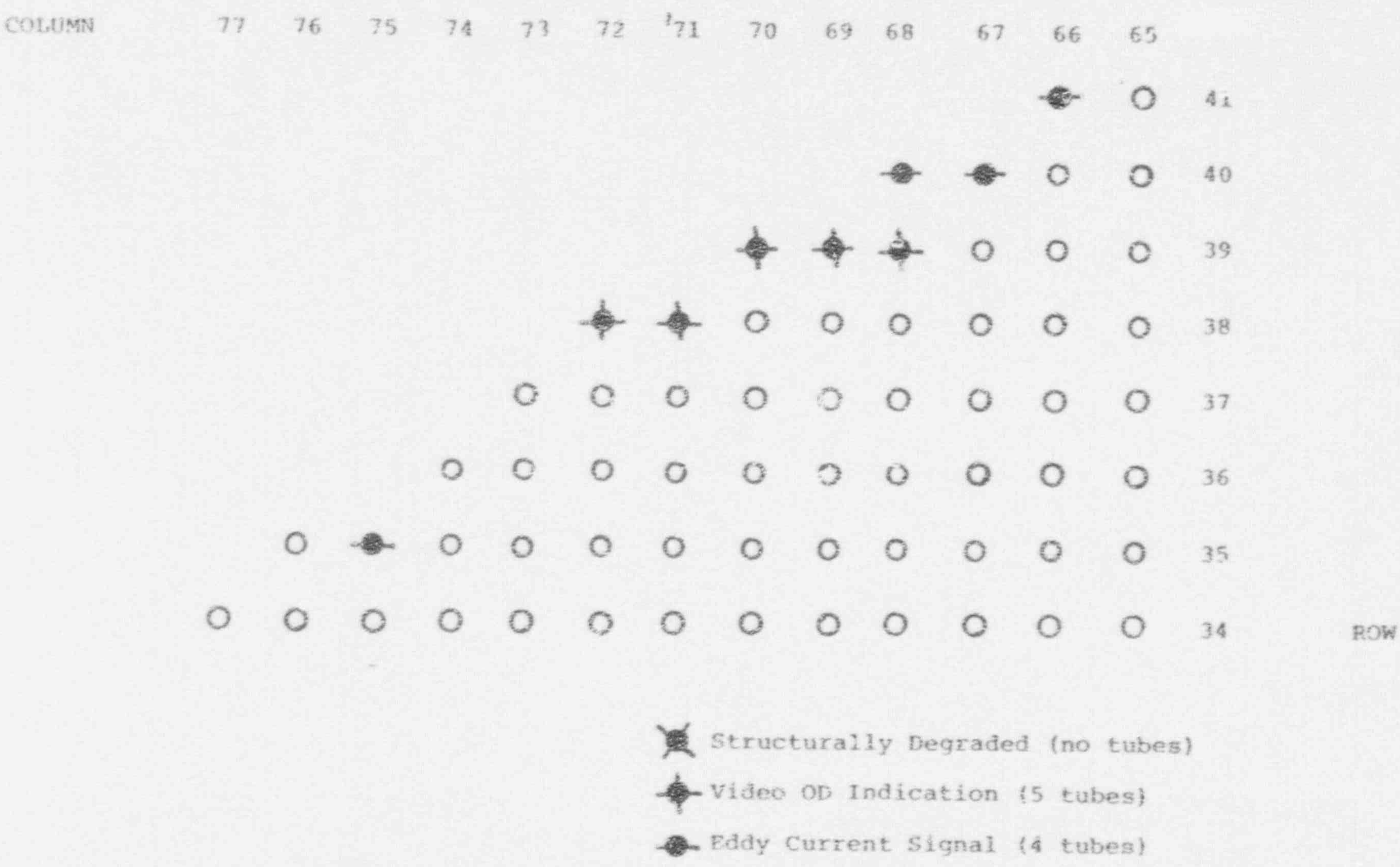
Eddy Current Signal (1 tube)

3/19/82

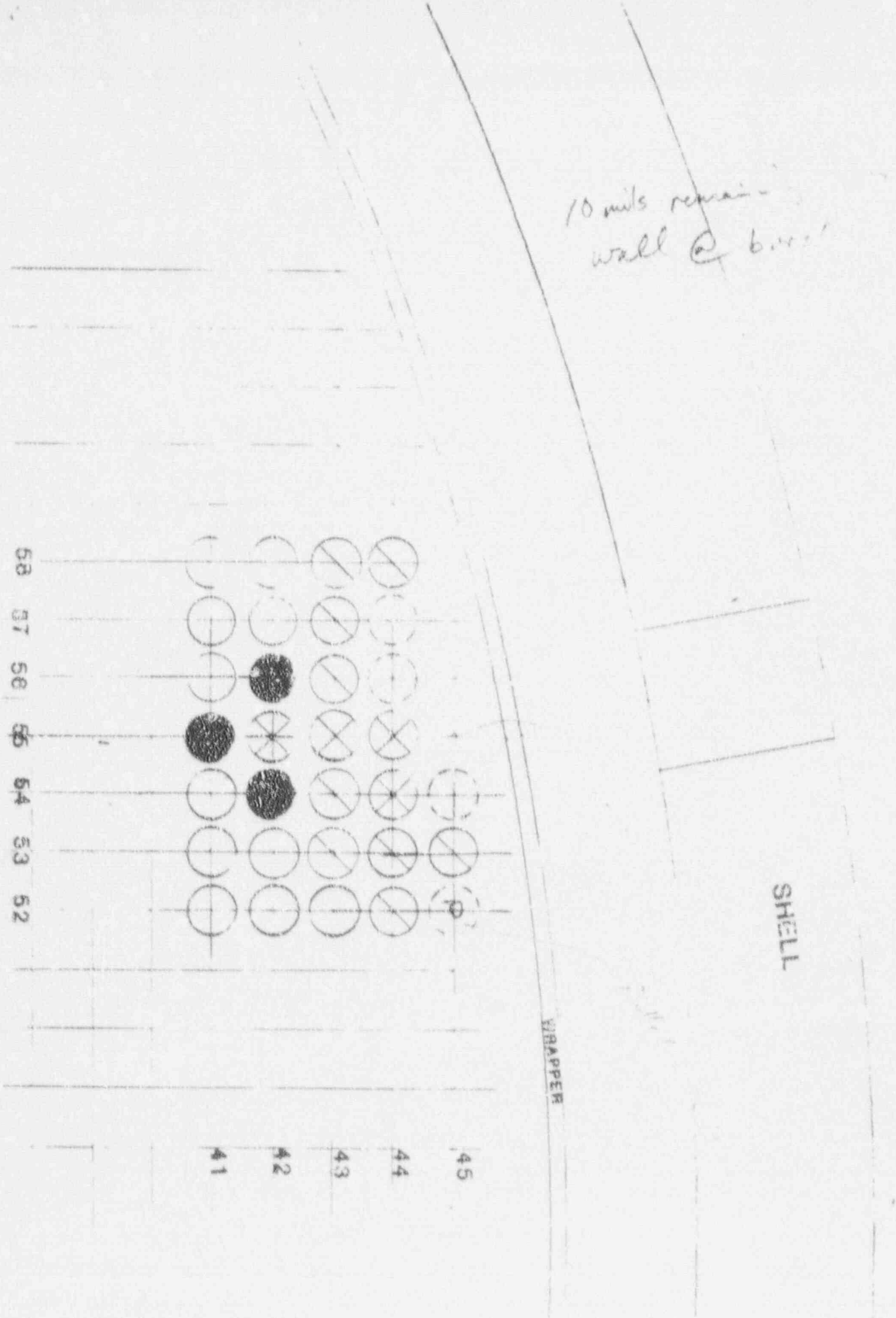
GINNA STATION

B-STEAM GENERATOR

RC40C70 AREA



3/19/82


10 mils remain-
wall @
SHELL
WRAPPER
58
57
56
55
54
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52
41
42
43
44
45

GINNA STATION
B-STEAM GENERATOR
CATEGORIZATION OF DEFECTS

CATEGORY	NO. 6 WEDGE AREA	R40C70 AREA	NO. 4 WEDGE AREA			NO. 2 WEDGE AREA
1. Structurally Degraded	R8C92 R11C91 R12C91 R14C90 R15C90		R42C55M R43C53 R43C54M R43C55M R43C56M R43C57 R43C58	R43C59 R43C60 R43C61 R44C52 R44C53M R44C54	R44C55M R44C56 R44C57 R44C58 R45C53 R45C54	
2. Video OD Indication	R9C91 R10C91 R13C90 R16C89 R17C89	R38C71 R38C72 R39C68 R39C69 R39C70		R45C51		
3. Eddy Current Signal	R15C89	R35C75 R40C67 R40C68 R41C66		R45C46 R45C47M R45C48 R45C49 R45C50		R12C2 R28C12 R30C15 R31C15 R32C15 R32C16 R33C15
4. Preventatively Plugged				R41C55 R42C54 R42C56		
TOTALS	11	9		28		7

M Metallurgical Samples

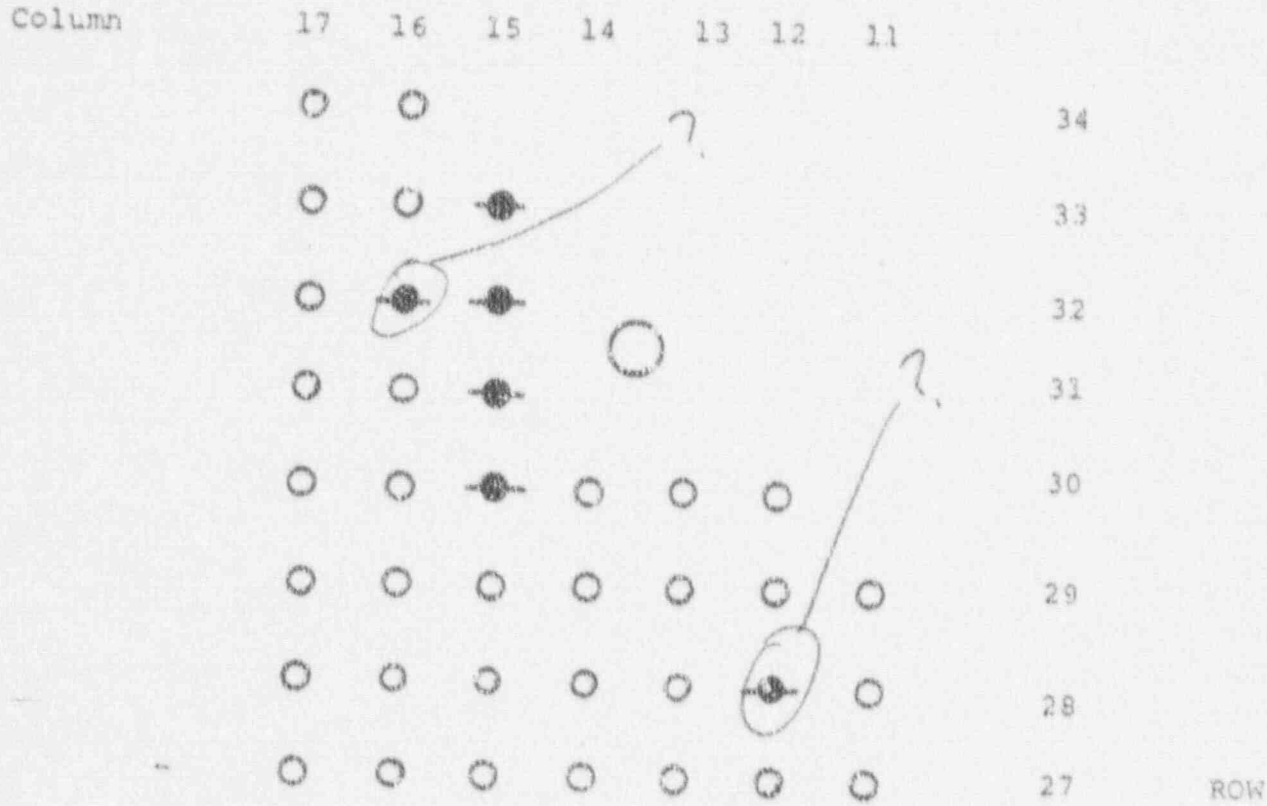
R45C52 pulled April 1978.

NRC Meeting
March 23, 1982

GINNA STATION

B-STEAM GENERATOR

NO. 2 WEDGE AREA



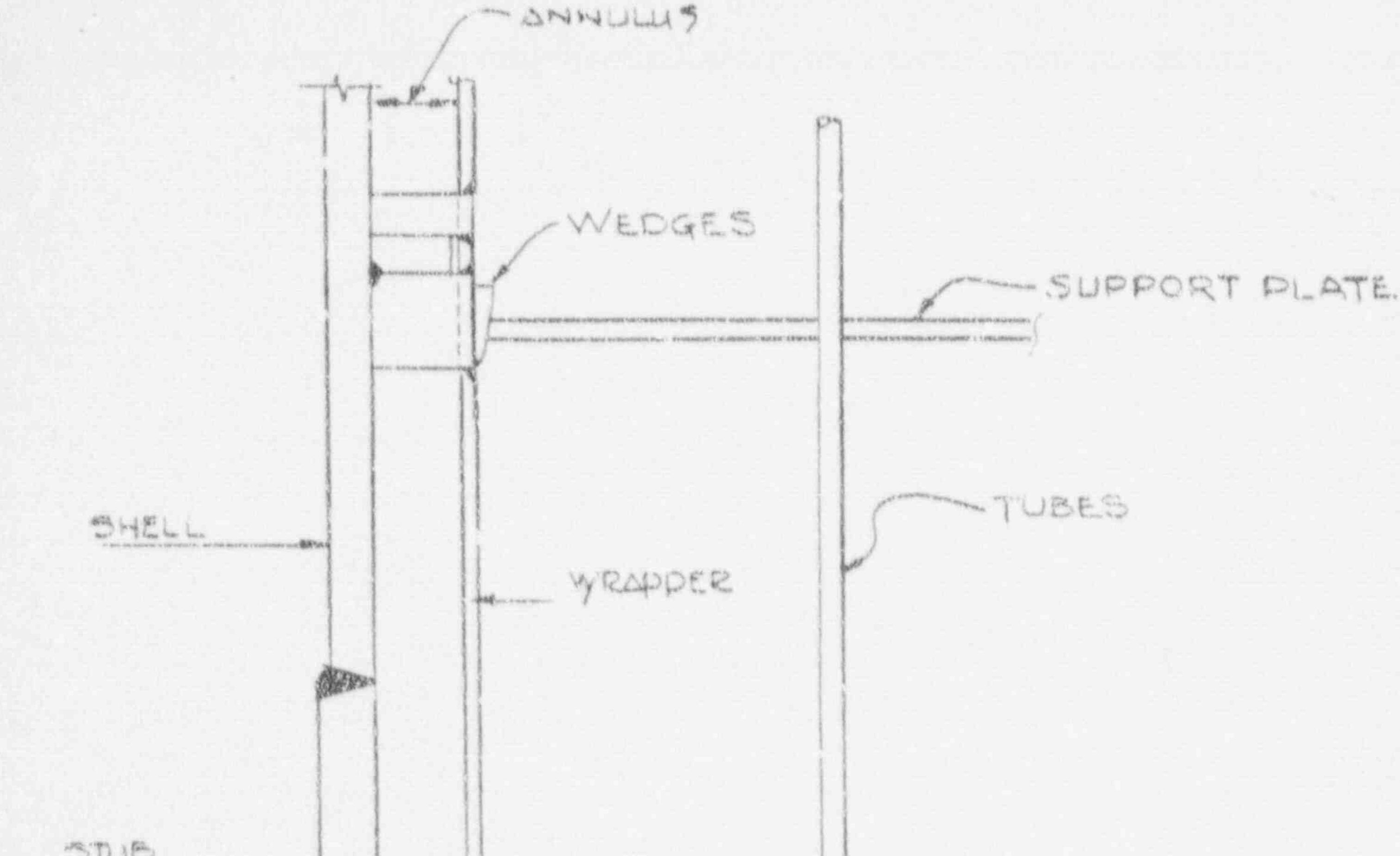
Structurally Degraded (no tubes)

Video OD Indication (no tubes)

Eddy Current Signal (6 tubes)
R12 C2 not shown

Stay Bar

3/19/82



0	ORIGINAL	INITIAL DATE				
NUMBER	REVISION		DRAWN BY	CHECKED BY	RESP. ENG.	ENG. MANG R.

ROCHESTER GAS & ELECTRIC CORP. ROCHESTER, NEW YORK	GINNA STA "B" STM GEN. 3" SHELL PEN.	SCALE
		NO.

RGE S/G-B POST TUBE REPAIR EVALUATION

CONDITIONS:

- TUBE REMOVAL
- SURFACE IRREGULARITY WITHOUT COLLAPSE
- SEVERED TUBES AT FIRST TSP

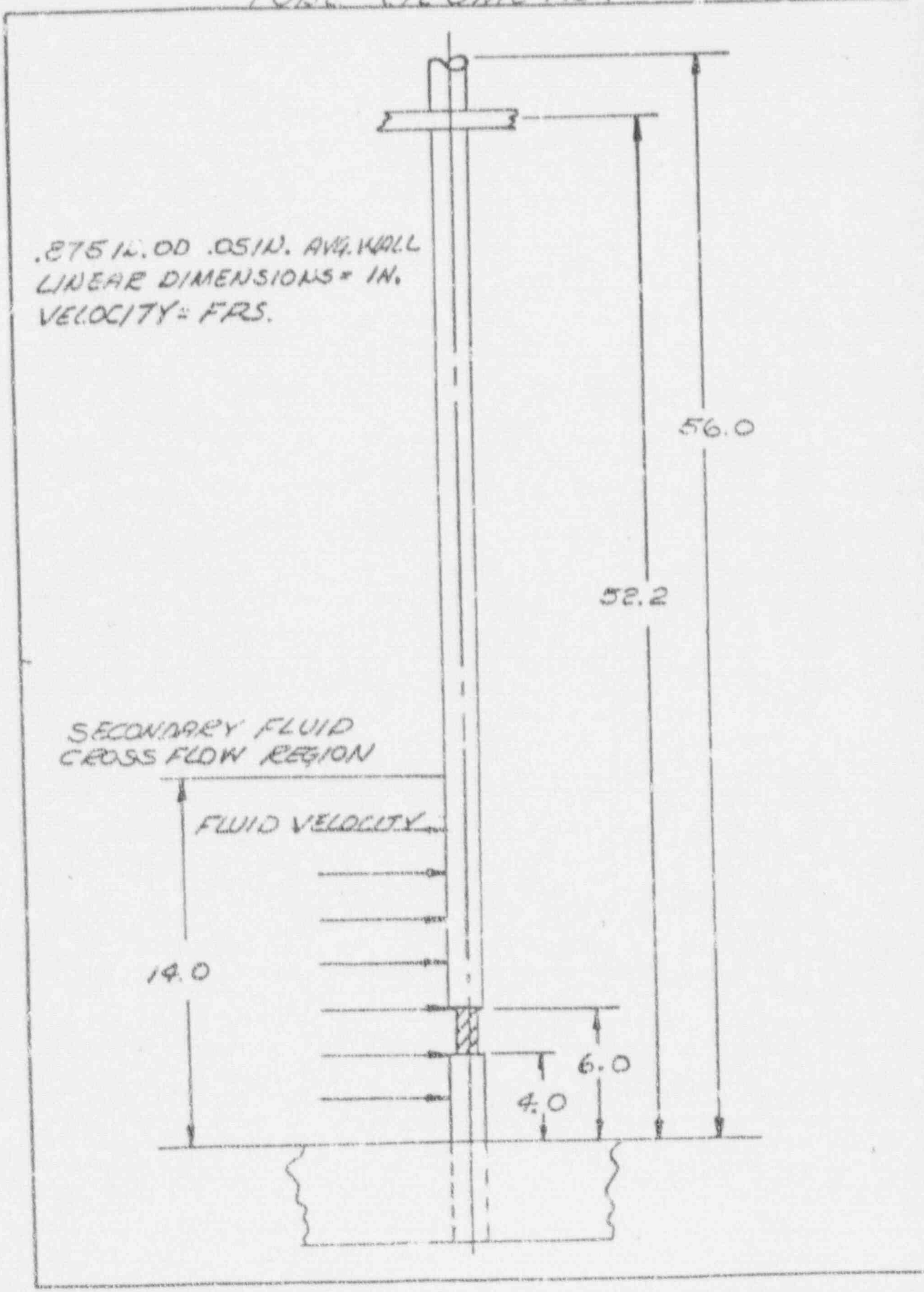
HYDRAULICS CONSIDERATIONS:

- TUBE FATIGUE DUE TO FLUID INTERACTIONS
    - FLUID-ELASTIC STABILITY
    - VORTEX SHEDDING
    - TURBULENCE
    - LOCAL FLUID EFFECTS - EDDYS, CRACK STABILITY
- FLOW VELOCITY AND QUALITY CHANGES

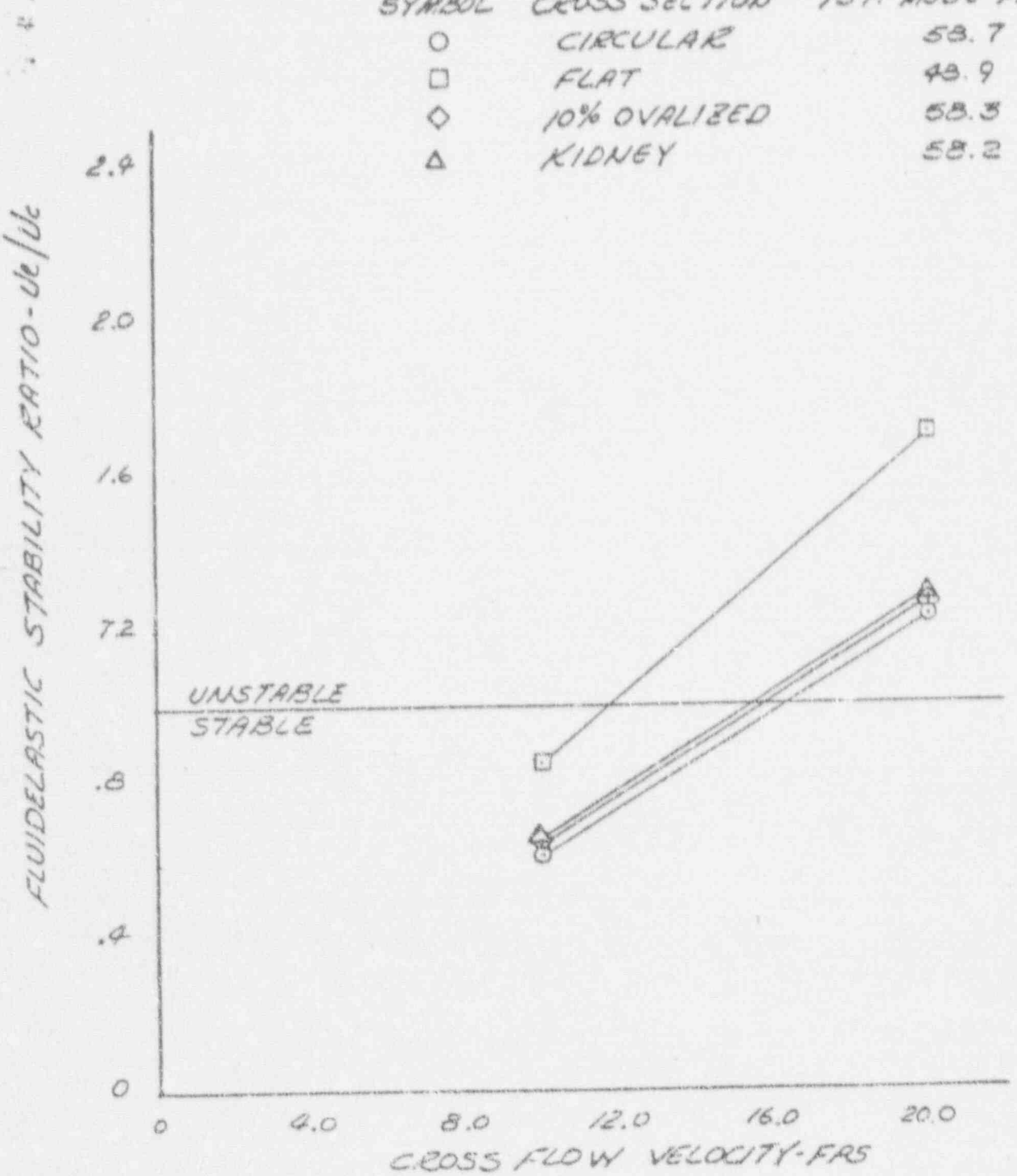
STRUCTURAL CONSIDERATIONS:

- FATIGUE MARGIN UNDER OPERATING TRANSIENTS
- COLLAPSE INTEGRITY
- STABILITY OF TUBES SEVERED BELOW TSP

TUBE GEOMETRY



FIXED-FIXED BOUNDARY CONDITIONS
DAMPING RATIO = 0.01

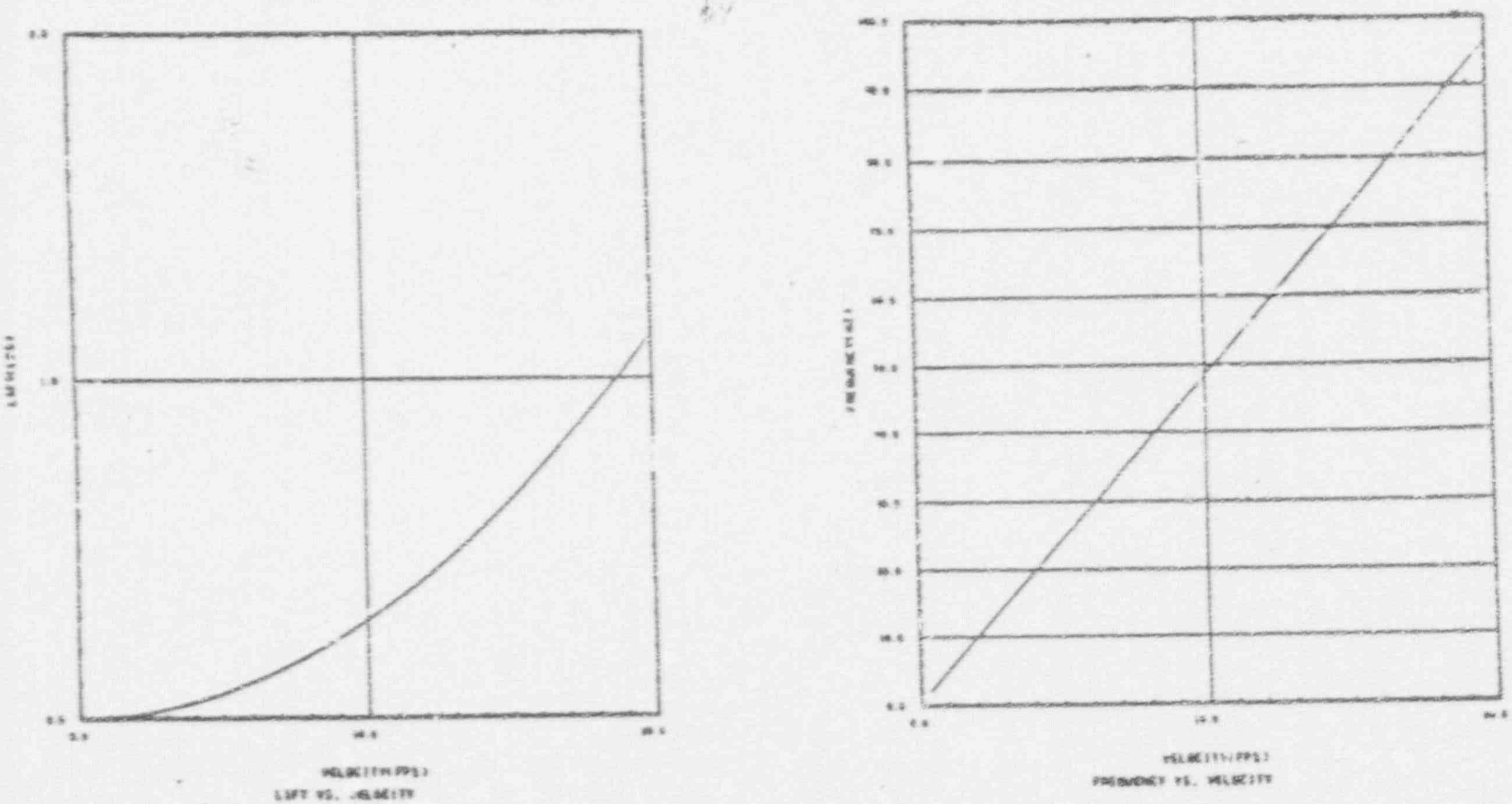


SUMMARY OF VORTEX SHEDDING AND TURBULENCE ANALYSES

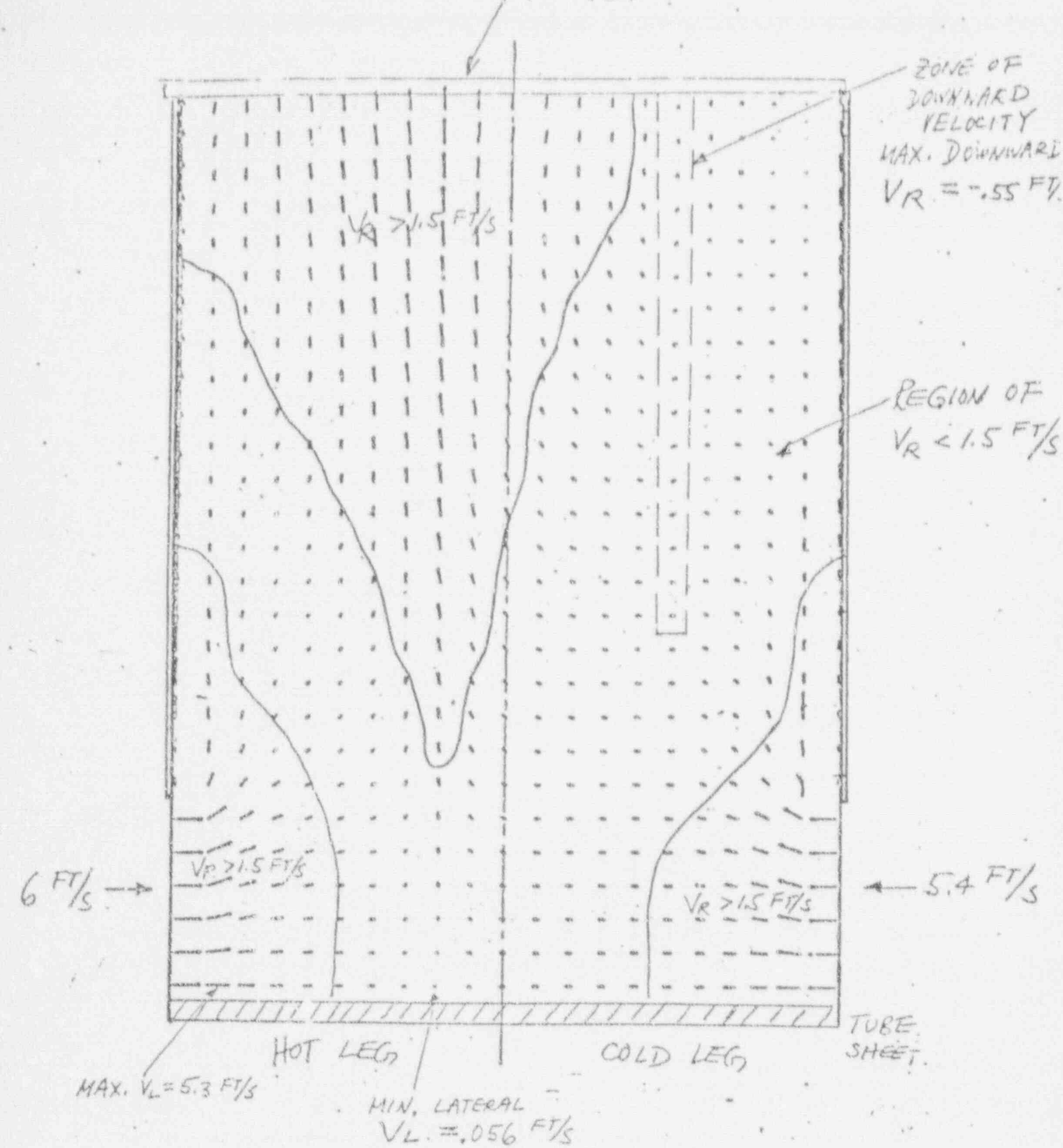
- FIXED-FIXED BOUNDARIES
- CROSS-FLOW VELOCITY, 10.0 FPS
- DAMPING RATIO, 0.01

CROSS SECTION OF DISTORTED ZONE	VIBRATION AMPLITUDES, MILS	
	VORTEX SHEDDING	TURBULENCE
CYLINDER (NOMINAL)	0.77	0.81
10% OVALITY	0.79	0.83
KIDNEY	0.79	0.83
FLAT	2.13	1.53

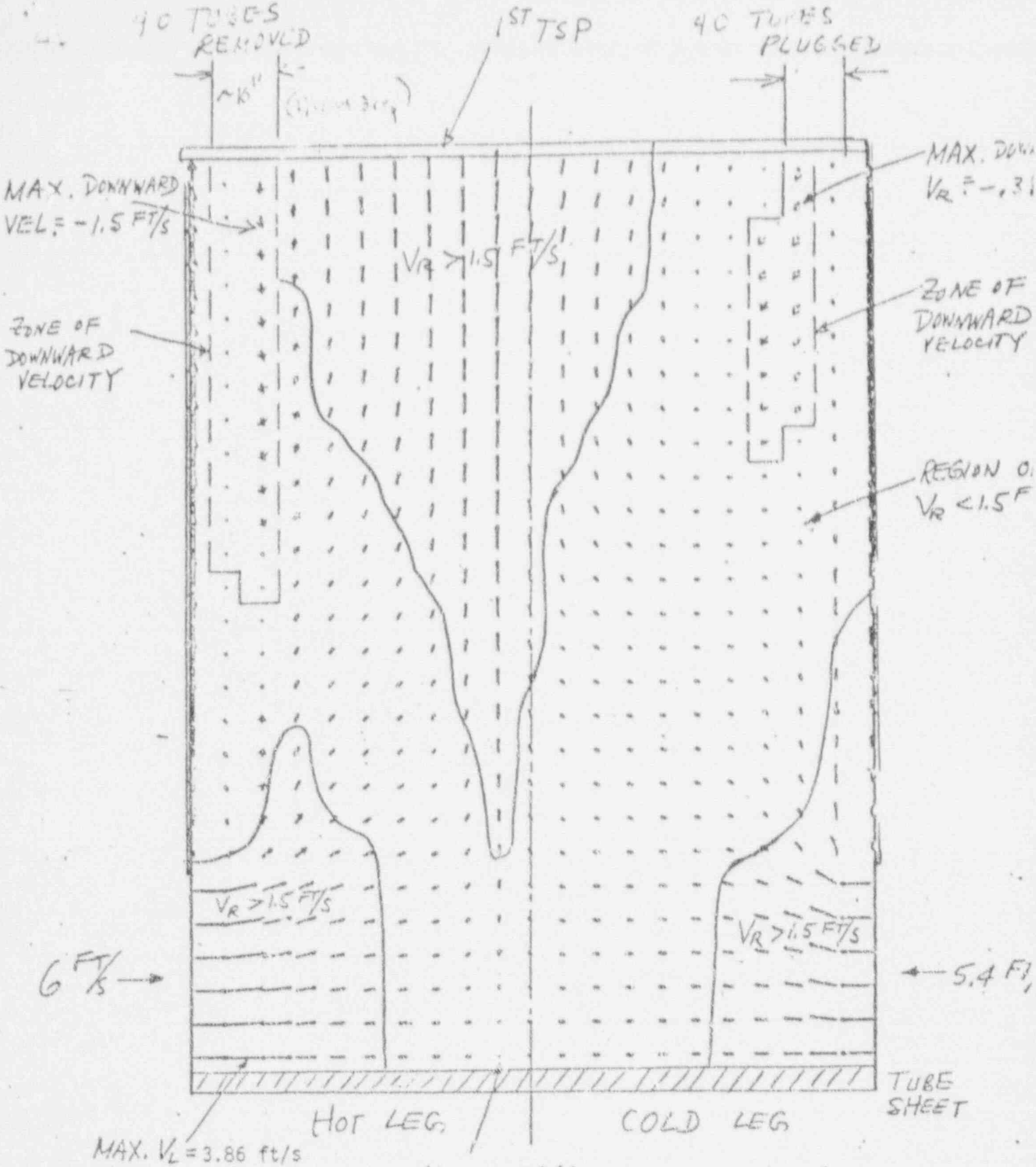
. VIBRATION AMPLITUDE DUE TO VORTEX SHEDDING AND CROSS-FLOW TURBULENCE ARE RELATIVELY UNAFFECTED BY SMALL DISTORTIONS AND SURFACE IRREGULARITY



OSCILLATING LIFT AND VORTEX - SHEDDING FREQUENCY FOR D = 0.5 INCH, H = 2.0 INCH



VELOCITY PATTERN OF NOMINAL CASE



VELOCITY PATTERN OF WITH 40 TUBES REMOVED AT HOT SIDE AND PLUGGED AT COLD SIDE

EFFECT OF HOT LEG TUBE REMOVAL ON CROSS-FLOW VELOCITY

(2-D MATHEMATICAL STUDY)

INPUT CROSS-FLOW VELOCITES: 6.0 ft/sec. hot leg
5.4 ft/sec. cold leg

CASE	AVERAGE VELOCITY IN TUBE REMOVAL REGION	MAX. GAP VELOCITY IN FIRST TUBE ROW DOWNSTREAM
NOMINAL	5.30	19.40
10 TUBES REMOVED	3.69	13.50
40 TUBES REMOVED	3.86	14.14

- TUBE REMOVAL DOES NOT ADVERSELY AFFECT FLOW VELOCITIES

FATIGUE EVALUATION OF SURFACE DAMAGED PLUGGED TUBE

(ASSUME FULL AXIAL RESTRAINT AT FIRST TSP)

- ENVELOPING TRANSIENT - PLANT LOADING/UNLOADING, 14,500 CYCLES
- ASSOCIATED LOADS
  - TEMPERATURE VARIATIONS

    PRIM ARY T_{HOT}: 547F (HOT STANDBY) TO 602F (100% POWER)

    SECONDARY T_{ST}: 547F (HOT STANDBY) TO 518F (100% POWER)
  - EXTERNAL PRESSURE RANGE: 795-1020 PSI
  - AXIAL TUBE LOAD RANGES
    - TUBE-TO-SHELL THERMAL MISMATCH: ± 780 lbs.

      ASSUMPTION - TUBE IN CONTINUOUS THERMAL EQUILIBRIUM WITH SECONDARY FLUID; STUB-BARREL WITH INFINITE THERMAL INERTIA
    - PLUGGED-TO-ACTIVE TUBE THERMAL MISMATCH: 0 TO + 1200 LBS.

      ASSUMPTION - SINGLE PLUGGED TUBE WITHIN A CLUSTER OF ACTIVE TUBES
- AXIAL BENDING LOADS
  - AS-BUILT MISALIGNMENT, 0.25 INCH
  - TS-TO-TSP THERMAL GROWTH MISMATCH, 0.05 INCH
  - TS ROTATION DUE TO PRIM-TO-SEC Δp, 0.08 INCH

FATIGUE USAGE CALCULATIONS

- MAXIMUM STRESS INTENSITY RANGE

  S_{ALT} = 56.25 KSI

  (ADJUSTED TO E = 26 x 10^3 KSI FOR ASME FATIGUE CURVE)

- ASSUMED STRESS CONCENTRATION FACTOR FOR SURFACE DAMAGE = 4.0 (MAX. PER ASME)

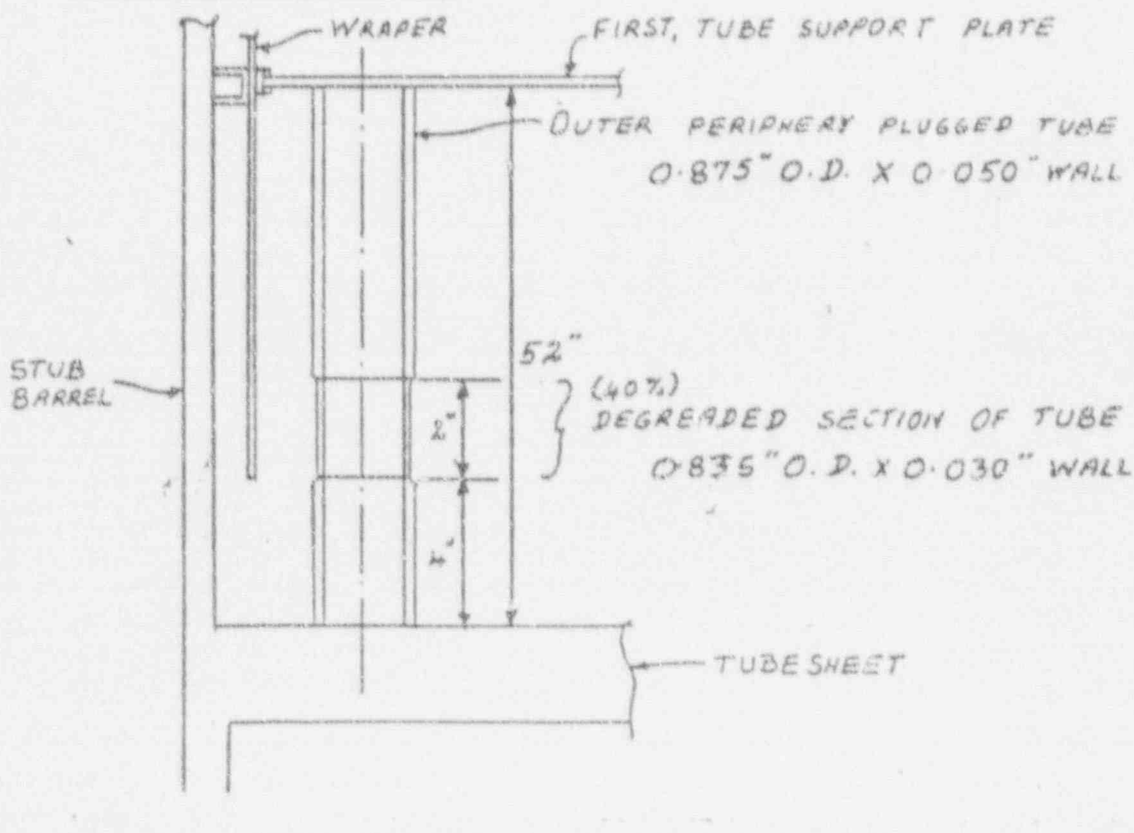
- NUMBER OF CYCLES n = 59,000 (THIS NUMBER REPRESENTS ALL TRANSIENTS LUMPED CONSERVATIVELY)

  MINIMUM ACTUAL USABLE CYCLES PER ASME CODE

  N = 135,000

- CALCULATED USAGE = n/N = 0.4303

TUBE GEOMETRY



COLLAPSE INTEGRITY EVALUATIONS

BASED ON EXTENSIVE LABORATORY TESTING

- COLLAPSE PRESSURE FOR NOMINAL TUBING ~ 5000 PSI

- COLLAPSE STRENGTH IS RELATIVELY UNAFFECTED BY SHORT ($\ell \leq$ TUBE DIAMETER), THROUGH-WALL TIGHT CRACKS

- FOR TUBE COLLAPSE, DUE TO THE MAXIMUM Δp ~ 1020 PSI REQUIRED WALL DEGRADATION IS ~ 80%, IF UNIFORM, AND > 90% IF LOCAL

TUBE COLLAPSE RESULTS FROM PLASTIC INSTABILITY AND REPRESENTS AN INSTANTANEOUS FAILURE MODE. OF ALL THE LOADING CONDITIONS FOR RGE TUBING, THE MAXIMUM Δp (~ 1020 PSI) OCCURS DURING NORMAL OPERATION WHICH, THEREFORE, REPRESENTS A PROOF TEST.