Wisconsin Electric POWER COMPANY
231 WEST MICHIGAN, MILWAUKEE, WISCONSIN 53201

November 23, 1979

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U. S. NUCLEAR REGULATORY COMMISSION
Washington, D. C. 20555

Attention: Mr. A. Schwencer, Chief
Operating Reactors Branch 1

Gentlemen:

DOCKET 50-266
STEAM GENERATORS
POINT BEACH NUCLEAR PLANT, UNIT 1

On November 5, 1979, we met with the NRC Staff at our request to review recent steam generator experiences at Unit 1 of our Point Beach Nuclear Plant and the results of tube inspections and tests on this unit. As a result of a petition directed to the Commission by Wisconsin's Environmental Decade dated November 14, 1979, NRC Staff requested a further meeting on this matter, which was held in Bethesda on November 20 with representatives of the NRC, Wisconsin's Environmental Decade, Public Service Commission of Wisconsin, Union of Concerned Scientists, Wisconsin Electric, and Westinghouse Electric Corporation and members of the press and public.

At this latter meeting, we presented information and data previously reviewed with the Staff in regard to the Unit 1 steam generator tube problems and responded to detailed questions of the Staff and petitioner. At the conclusion of the meeting, Mr. Darrell Eisenhut requested that we submit in writing the materials presented and reviewed during the meeting. This transmittal is in response to that request.

Attached hereto are enclosures covering the various items of our discussions as follows:

1. Chemistry History

   During this phase of the discussion, we reviewed the early phosphate chemical treatment utilized at Point Beach Nuclear Plant, methods and degree of chemistry control, changes in phosphate chemistry, chemical feed, and steam generator modifications previously adopted, and the change to, and experience with, all volatile chemical treatment.

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2. History of Tube Defects and Plugging

We discussed the early experience with the tube thinning and cracking on Unit 1 which has been arrested since 1975, together with the reasons believed responsible for this experience. We also reviewed the limited denting phenomena observed at Point Beach, and discussed why this plant did not experience significant tube degradation due to this cause. We described the early signs of crevice corrosion cracking and the recent large number of such observations in August and October of this year, together with their distribution, size, probable cause and effect. Additionally, we discussed quality assurance activities in respect to such inspection and repair operations and employe radiation exposure considerations.

3. Physical Properties and Testing - Safety Considerations

Based on the August and October inspections, we described the analytical program we had undertaken, including the removal of three tube sample specimens from various areas of the "A" steam generator of Unit 1. We described the removal technique and forces, the metallurgical and physical tests applied to the specimens, and the test results of all samples removed. We discussed the design of the steam generator and the intergranular corrosion attack found in the unrolled crevice area of the tubes within the tube sheet. We discussed the safety implications of this phenomenon in respect to loss of coolant, main steam line break, and feedwater line break accidents.

4. Accident Analysis

We reviewed the results of emergency core cooling system analyses performed with 18% steam generator tubes plugged at 2250 psi and 2000 psi main coolant system pressure and with nominal and reduced main coolant system temperatures.

5. Actions to Minimize Degradation and to Assure Safety

We described the various actions we had taken and proposed in operating conditions, testing programs, and operating limits to assure public health and safety and to minimize further steam generator tube degradation. We discussed immediate programs being implemented and long-term solutions under investigation.

For details in respect to each of these principal subjects, please refer to the attached enclosures. We also would refer you to our letters of November 2, 1979 and November 19, 1979 in respect to 2000 psi operation and ECCS analysis.

In summary, we made the following observations and conclusions:

1. The early difficulties with Unit 1 steam generator tubes were principally due to thinning or cracking caused by phosphate chemical treatment employed between unit start-up and September 1974, when a change to all volatile chemical treatment was made. Since 1975 no thinning or cracking problems have been observed with this unit.

2. A minor amount of denting was observed in Unit 1, but this phenomenon has not progressed to any appreciable extent.

3. Indications of crevice corrosion attack appeared in 1977, but remained relatively minor until August 1979 when 99 tubes (1.5% of total) required plugging due to this cause. Inspections conducted during the refueling outage of this unit in October 1979 revealed an additional 134 tubes (2.1%) having this type defect.

4. Based on samples removed from the Unit 1 steam generator and from other plants in previous years, these defects are concluded to be intergranular corrosion attack of the Inconel 600 tube material in the narrow crevice area caused by residue of caustic materials remaining from phosphate chemical treatment and possibly from earlier condenser tube leakage.

5. This corrosion is confined to the crevice area. No evidence of this intergranular attack was found in areas of tube above the tube sheet.

6. Forces required to remove the sample tubes were as follows:

Tube No.	Pulling Force, Lbs.
R15C45	25,600 (tube broke in pulling)
R22C37	25,400
R20C73	13,000

A force of 28,500 pounds was exerted on Tube R15C45, at which time the pulling tool failed. This tube was subsequently broken 1-1/2" below the top of the tube sheet with the force indicated above. These forces demonstrate there is no safety concern with respect to tube pull-out of bundle lifting with steam or feedline break accidents.

7. Burst tests conducted on three samples from two tubes were as follows:

Tube No.	Burst Pressure, psi
R22C37	11,700 (yield, no burst)
R22C37	6,800
R15C45	5,100

All bursts were by longitudinal failures. No circumferential failures were observed. The first five-inch sample of the R22C37 tube (above) was taken from a location which transversed the tube sheet top-tube interface. The other two five-inch samples were from within the crevice region. These tests demonstrate that even the significantly degraded tubes have a capability to withstand the maximum accident primary-secondary differential pressure of 2000 psi with margins of safety of 2.5 or greater. A new tube burst pressure is nominally in the 10-12,000 psi range.

8. Metallurgical examination reveals sound tube metal under the area of corrosion attack having metal properties equivalent to virgin material. Metal thickness required for various conditions of operation and accident are as follows:

Double-ended failure during steamline break	0.005 inch
Tube rupture during normal operation	0.008 inch
Tube rupture during steamline break	0.013 inch
No collapse during LOCA	
(With 6% ovality)	0.020 inch
(With zero ovality)	0.011 inch

Because 6% ovality in the crevice is deemed impossible, it is believed that 70% wall thickness degradation would still leave sufficient material of sound metallurgical capability to withstand accident conditions, even if intergranular attack extended to this depth in areas of tube above the tube sheet. Since these tube defects are confined to the tube sheet crevice area, even greater tube wall penetration can be tolerated without exceeding safety requirements under accident conditions.

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9. Present eddy current testing has demonstrated its capability to detect cracks from a range of 20% through wall to full-wall penetration. This technique, however, is not an effective means of detecting intergranular corrosion in the absence of cracks. Because a diametrically unrestrained tube, such as in the space above the tube sheet and outside tube support plates, expands under internal pressure, intergranular corrosion in such areas would be revealed as cracks. In the tightly constrained areas within the tube sheet, tube expansion under internal pressure is effectively precluded. While this makes eddy current indication of intergranular attack incapable, the totally contained tube cannot expand under internal pressure to cause significant cracking or rupture during normal or accident conditions.

10. Tube clearances within the tube sheet can vary because of manufacturing tolerances from .016 in to .022" on the diameter. These clearances are probably further reduced by the caustic and corrosion products. The tubes in the crevice area are, thus, tightly confined within the tube sheet, which severely limits any primary to secondary leakage and prevents tube collapse in the event of excessive secondary to primary pressure differential.

11. ECCS analysis demonstrates that operation with 18% of the tubes plugged is well within established safety criteria at either 2250 psi or 2000 psi reactor coolant system pressure or at nominal or reduced primary system temperatures.

12. No tube failures due to crevice corrosion have occurred on the cold leg side of the Point Beach steam generators. Research indicates such intergranular corrosion attack is sensitive to temperature.

13. While we conclude that safe operation of Point Beach Unit 1 is not presently jeopardized, we nevertheless intend to proceed with the following program to provide additional assurance of continued safety:

    a. Conduct an 800 psid hydrostatic test, secondary to primary, before return to power. Such test pressure exceeds the pressure which might be imposed on the steam generator tubes in the event of a loss of coolant accident. Should any significant leakage develop, the failed tubes will be plugged. (This test was successfully performed on Unit 1 on November 12, 1979.)

b. Conduct a 2000 psid primary to secondary hydrostatic test prior to return to power. Should any significant leakage develop, tubes will be plugged. This test pressure exceeds that which could develop during a steamline or feed level break and, thus, demonstrates the tubes' ability to maintain their integrity during such events. (This test was successfully performed on November 20, 1979.)

c. Presuming NRC approval of the Technical Specification change previously requested, operate the reactor coolant system at the nominal pressure of 2000 psig rather than 2250 psig. This reduces internal pressure stresses during operation approximately 15%.

d. Continue close surveillance of primary to secondary leakage and shutdown and plug leaking tubes if:

   1. Sudden leakage of 150 gpd (0.10 gpm) occurs, or

   2. Any leakage of 250 gpd (0.17 gpm) is experienced, or

   3. Rate of change of leakage increases above 15 gpd per day (0.01 gpm) between 150 gpd and 250 gpd total.

e. Repeat 2000 psid primary to secondary hydrostatic test in approximately 30 days and, if satisfactory, again, in 60-90 days. Should any significant leakage develop per Item d above, leaking tubes will be plugged.

f. Increase the frequency of eddy current testing of Unit 1 steam generators A and B by performing an eddy current test in accordance with Technical Specifications within one year of return to power rather than in two years as now provided. All eddy current tapes to be reviewed by qualified (Level III) reviewers.

14. On return to power operation, we are planning the following program in an attempt to retard further tube degradation:

a. Reduce reactor coolant system hot leg temperature to approximately 557°F. This will result in lower secondary steam pressure and, hence, lower power output due to limited flow capability of main turbine control valves. Maximum output under these conditions is expected to be 83% full power or 413 MWe net. Testing will be performed to assure main steam moisture carryover does not exceed design value of 0.25%.

b. Continue close surveillance of feedwater chemistry conditions and condenser tube leakage.

c. Perform sludge lancing within 12 months of return to power.

The effects of these operating conditions will be reviewed with the NRC Staff if any significant results are obtained or if any significant changes to this program are contemplated.

15. Although Wisconsin's Environmental Decade petition contained a number of statements which we believe are in error, its major safety concern relates to the American Physical Society, Lewis Report, (1975), reference to the potential for steam generator tube failure during a severe LOCA which could adversely affect ECCS performance. Since the present tube degradation problem at Point Beach is confined to the tube sheet crevice area, and since a tube collapse within the tube sheet area cannot occur during a LOCA or otherwise, the possibility of having secondary side inventory interfere with blowdown and reflood during a LOCA does not exist. Insofar as rupture of a tube above the tube sheet during LOCA is concerned, there is nothing in the present or foreseeable steam generator tubing characteristics inspection or operating programs that constitutes a change from previous conditions.

In conclusion, we have demonstrated that continued operation of Unit 1 at Point Beach would not compromise public health and safety. The existing basis for continued safe operation of this unit is still applicable. We have shown that the intergranular attack is confined to the tube sheet crevice location. The burst tests demonstrate even the affected tubes have ample margin as compared to calculated loads. Tensile tests, plug tests, and stress analysis confirm tube integrity. Tube removal forces demonstrate the capability of the tubes to carry substantial loads. Our operating history and that of others confirm that detectable leakage appears before serious tube degradation. Proposed operating and testing programs demonstrate safety margins and may retard further degradation.

As we advised you previously, Unit 1 will not be returned to power without NRC concurrence.

We appreciate your continuing immediate review of this matter. Please telephone us if you have any question or require further information.

Very truly yours,

Sol Burstein

Sol Burstein
Executive Vice President

Enclosures

Copy to: Mr. Clarence Riederer
Public Service Commission of Wisconsin

Ms. Kathleen Falk, General Counsel
Wisconsin's Environmental Decade, Inc.

Marian Moe, Esquire
Office of General Counsel H-1047
U. S. Nuclear Regulatory Commission

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ENCLOSURE 1

Chemistry History

The chemistry history of Unit 1 is summarized in Viewgraph 1.

From initial startup at the end of 1970 to January 1972, phosphate chemistry was used for steam generator chemistry control. In addition to continuous feed, phosphates were batch-fed to the steam generators in attempts to maintain specified phosphate concentrations. Steam generator blowdown was intermittent, in accordance with then-existing control practices. During early 1971, Unit 1 experienced numerous condenser tube leaks, free caustic was present in the steam generators and sodium to phosphate (Na/PO_4) ratios were generally high. The condenser leakage problems decreased after modifications to the condenser in 1971. Na/PO_4 ratios remained high and free caustic was present during the remainder of the period.

From January 1972 to September 1972, phosphate concentrations were increased using the same batch and continuous feeding methods. The periods of operation with free caustic were reduced and the Na/PO_4 ratios were generally controlled between 2.0 and 2.6. The unit was shut down for its first refueling in September 1972.

Following completion of the refueling and maintenance outage in March 1973, the phosphate feed system was modified to allow better control and continuous blowdown was initiated. In

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early 1974, the Na/PO_4 control ratios were adjusted to between 2.3 and 2.6. During the April 1974 refueling shutdown, the steam generators were sludge lanced.

Between May and October 1974, phosphate chemistry control was further improved and in June 1974 tube lane blocking devices were installed to improve circulation and sludge removal. In September 1974, an online conversion to all volatile treatment (AVT) was performed by discontinuing phosphate feed and initiating maximum steam generator blowdown. The online conversion was marginally successful, however, and free caustic was confirmed in November 1974. During November, a 48-hour shutdown and soak were performed for phosphate removal. The unit was sludge lanced and returned to power with AVT treatment.

During 1975, as shown on Viewgraph 2, operation with AVT chemistry indicated free caustic was present during operation and sodium and phosphate hideout return was present during unit shutdown. During 1976 and 1977, levels of free caustic generally decreased although free caustic was frequently detected. Sodium and phosphate continued to be detected during unit shutdowns. In 1978 and 1979, free caustic was normally below detection limits and sodium and phosphate, although still present, were much lower during unit shutdown.

The continuing improvement in AVT chemistry control from 1975 to present has been due in large part to increased attention to condenser leakage and the continuing development of leakage detection capability. In 1978, additional condenser hotwell cation conductivity devices were installed on individual

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hotwells to allow identification of condenser leaks in individual condenser sections. Conductivity values are recorded for confirmation of condenser integrity. Leak detection limits are in the order of 0.05 to 0.1 gallons per minute and Freon detection instrumentation has been used to identify tubes with very small leaks. When a condenser leak is identified, administrative policy is to reduce power as soon as practicable, isolate the leaking portion of the condenser, and plug the leaking tube. These monitoring capabilities and policies ensure condenser integrity and minimize introduction of contaminants to the steam generator.

It was pointed out, in response to a question, that while chloride spikes approaching 10 ppm were present in steam generator blowdown after shutdown, normal operating chloride levels were approximately 100 ppb. Chlorides, while present, do not appear to be a dominant factor in the crevice corrosion phenomenon.

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UNIT 1 HISTORY
PHOSPHATE CHEMISTRY

Startup to Jan 1972:

Intermittent batch feeding of phosphate in addition to continuous feed, intermittent blowdown (permitted by existing control practice), high Na/PO_4 ratios, caustic present, condenser leaks. Leak in April 1971 of 20-67 gpd

Jan 1972 to Sept. 1972 refueling

Increased phosphate concentrations, same feed methods, reduced periods of free caustic, chemistry generally controlled to Na/PO_4 between 2.0 and 2.6. Leak remained at low rates.

March 1973 - April 1974

Phosphate feed system modified to allow better control, control changed to $2.3 < Na/PO_4 < 2.6$, continuous blowdown, free caustic under control, no leakage.

April 1974 - May 1974

Sludge lanced, thinning detected

May 1974 - October 1974

Good control, Na/PO_4 between 2.3 and 2.6. Online conversion to AVT in Sept. 5 gpd leak occurred in August.

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November 1974 to March 1975

Confirmed free caustic, 48 hr. soak at 350 to 400F to remove phosphates, sludge lanced. Feb. 1975 tube rupture at 125 gpm. Phosphate reached ~ 200 ppm during cooldown, sludge lanced to remove.

POINT BEACH UNIT 1
Blowdown Chemistry · SG A

Jan-Dec 1975 - All Volatile Treatment
- Free Hydroxide persistent up to 0.6 ppm
- Sodium & Phosphate returns during shutdown
  $Na/PO_4 > 3$, Na to 37 ppm

Jan-Dec 1976 - All Volatile Treatment
- Continued presence of Free Hydroxide, to 0.2 ppm
  - decreasing trend
- Sodium & Phosphate returns during shutdown
  Na/PO_4 1 to 4 , Na to 18 ppm

Jan-Dec 1977 - All Volatile Treatment
- Free Hydroxide continues at up to 0.2 ppm
- Sodium & Phosphate returns during shutdown
  Na/PO_4 up to 14 , Na to 150 ppm

Jan-Dec 1978 - All Volatile Treatment
- Free Hydroxide usually below detection, <0.05 ppm
- Sodium release during shutdown < 3 ppm

Jan-Oct 1979 - All Volatile Treatment
- Free Hydroxide usually below detection, 0.05 ppm
- Releases during shutdown
  - Na to 6 ppm
  - Cl to 10 ppm
  - PO_4 to 1.5 ppm

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ENCLOSURE 2

History of Tube Defects and Plugging

The first indication of possible tubewall degradation at Point Beach occurred in Unit 1 in April 1971 (approximately six months after initial criticality) when steam generator leakage was detected. This leakage varied with time but always was less than 0.05 gpm. Upon inspection of the steam generator tubing during the first refueling and maintenance outage (October 1972 - March 1973), the location and mechanism of the tube degradation were identified. Stress corrosion cracking was identified on the tube surfaces just above the top of the tubesheet, within the boundaries of the sludge deposition zone in the central region of the hot leg side of the tube bundle. The tubes affected exhibited axially oriented cracking in the short length of tube generally within the sludge deposition zone.

From March 1973 to August 1974, no steam generator leakage was observed at Point Beach in either Unit 1 or Unit 2. During refueling outages in both units in 1974, indications of minor tubewall degradation were detected in both units. The distribution of eddy current indications (most of which were less than 20 percent of the wall thickness) indicated that the corrosion mechanism was localized thinning of the tubewall due to phosphate corrosion. These indications were largely confined to the same region in which cracking had been found in 1972 in Unit 1, that is, within the region of the sludge deposition zone. There were also scattered indications of thinning noted in certain areas at the tube support plates where concentration of chemicals could occur.

In February 1975, a steam generator tube break of approximately 125 gpm occurred in Unit 1. After shutdown, eddy current inspection revealed indications of tubewall penetration in the same area where tube degradation occurred in 1972. The cause for these indications and the tube break was judged to be stress corrosion cracking.

The first steam generator leak in Unit 2 occurred in August 1975 in a single peripheral tube at the top of the tubesheet. The cause of this leak was not determined and none of the neighboring tubes had indications of tube degradation, although eddy current inspection indicated some thinning of tubes in the central region of the tube bundle. Analysis of the eddy current data also indicated the presence of minor denting in Unit 2. Minor denting was subsequently discovered in Unit 1 during an eddy current inspection performed in November, 1975.

The only other significant occurrences of tube degradation observed at Point Beach is intergranular corrosion of the tubes within the tubesheet crevice region of Unit 1. The first observation of this phenomenon at Point Beach was accompanied by tube leakage in September 1977. Subsequent limited occurrences of this phenomenon in Point Beach Unit 1 were confirmed in September 1978 and March 1979. In August 1979 and October 1979, significant numbers of tubes in Unit 1 were found to be affected by intergranular corrosion in the crevice region.

Viewgraphs 1 and 2 provide a summary of tubes plugged in each of the steam generators for Units 1 and 2, respectively. Plugged tubes have been categorized by type of degradation and by time of plugging. The denting phenomenon, although present in many of the steam generator tubes of both units, has not resulted in plugging of significant numbers of tubes in either unit. Stress corrosion cracking above the tubesheet and tube thinning accounted for the majority of tubes plugged in the first few years of operation. Based on more recent experience, both of these corrosion mechanisms appear to have been arrested. Crevice corrosion has accounted for less than half the tubes plugged in Unit 1 to date. It has not been observed on Unit 2 even though Unit 2 has operated for approximately the length of time which it took for crevice corrosion to be observed in Unit 1. As shown in Viewgraphs 1 and 2, less than one-tenth the number of tubes have been plugged in Unit 2 as in Unit 1.

The general distribution of tube plugging is shown on Viewgraphs 3 and 4 for steam generator A and 5 and 6 for steam generator B and indicate tubes plugged after the August 1979 and October 1979 shutdowns. As shown in the viewgraphs, the majority of tubes plugged are in the sludge deposition zone ("Kidney zone") of the steam generators.

Viewgraph 1 indicates a total of four tubes plugged at various times due to mistakes in identifying the correct tube for plugging. Considering the total number of tubes plugged in Unit 1 steam generators and the difficulties associated with working in confined and high radiation areas, this number of errors is not unexpected.

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To ensure that the correct tubes are plugged, the following general procedures are used:

1. Following designation of a tube to be plugged, a confirmation is made by eddy current inspection.

2. The hot leg end of the tube is located and marked with the aid of templates used during eddy current examinations.

3. A probe is inserted over the U-bend and out the cold leg end of the tube. This tube end is then also marked.

4. Explosive plugs and primer cord are inserted into both ends and the correct tubes are, again, verified by visual examinations.

5. Following plugging, tubesheet photographs are taken and inspected to verify that the correct tubes have been plugged.

If the shutdown is only for plugging a leaking tube, there is no need for tubesheet photography. However, the plugged tube is marked on the previous photographs.

The distribution of crevice defects by depth of the defect and by defect location is shown in Viewgraph 7. Approximately 80 percent of the defects had greater than 80 percent through-wall penetration. Approximately 40 percent of the defects in steam generator A are within the top three inches of the tubesheet crevice compared to approximately 24 percent for steam generator B. The distribution of defects by location appears to be more uniform in steam generator B than in steam generator A. In addition to the data shown in Viewgraph 7, approximately 28 and 10 percent of the defects in steam generator A are within the top two and one inches of the crevice, respectively. The corresponding values for steam generator B are approximately 10 and 8 percent, respectively.

Eddy current testing is currently not able to detect intergranular corrosion within the tubesheet. Significant (>20 percent through wall) cracks or tube wall penetrations in the tubesheet area are, however, detectable by eddy current testing. The conditions within the tubesheet crevices are such that the tubing material affected by intergranular corrosion is held in place by the tubesheet itself and the crevice condition shows a minimum of grain dislocations or material loss. As a result, the grains in the suspect region remain in physical and electrical contact providing a continuous path for eddy currents induced in the tubewall when the eddy current test is performed. The material, therefore, may show no eddy current indication of the corrosion within the tubesheet crevices unless there is cracking through a portion of the tube wall. Work is underway to develop simulations in the laboratory for the purpose of determining the sensitivity of eddy current testing to intergranular corrosion and to evaluate alternative methods where feasible.

Recent experience with tube degradation due to intergranular attack indicates that more frequent inspections by eddy current testing may result. If further tubes are pulled

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for analysis, this will also require radiation exposure beyond tube inspection and plugging. Radiation exposure estimates from recent refueling inspections and the October 1979 refueling are as follows:

	Exposure to Steam Generator Personnel
1976	40 man-Rem (3 to 4 for sludge lancing)
1977	118 man-Rem (3 to 4 for sludge lancing)
1978	40 man-Rem (3 to 4 for sludge lancing)
Oct. 1979	255 man-Rem (estimated)

The 1977 exposure is higher than normal due to difficulties in repairing leaking explosive tube plugs and, thus, are not believed to be typical. Preliminary estimates of the exposure during the October 1979 refueling are as follows:

Steam generator decontamination	20 man-Rem
Sludge lancing, eddy current testing, and tube plugging	80 to 100 man-Rem
Tube pulling	135 to 155 man-Rem

The tube plugging in 1976 and 1978 was minimal; therefore, a reasonable estimate of the exposure during a normal eddy-current inspection is in the order of 36 man-Rem. Comparing this to the total exposure for eddy current testing and tube plugging in October 1979 indicates exposures in the order of 50 to 60 man-Rem for plugging approximately 140 tubes, or 0.4 man-Rem per tube. Three tubes were pulled for analysis with an estimated exposure in the order of 150 man-Rem, or 50 man-Rem per tube. From these data, the following exposure commitments are estimated for a tube inspection outage:

Sludge lancing	4 man-Rem
Eddy current inspection	36 man-Rem
Tube plugging	0.4 man-Rem per tube
Tube pulling	50 man-Rem per tube

The basic technique used to minimize radiation exposure during steam generator inspection operations is to limit the time spent in the vicinity of, or inside, the steam generators. Techniques used to accomplish this are as follows:

- Use of experienced personnel as far as practical
- Remote readout instrumentation and television surveillance of operations
- Remotely operated inspection equipment which requires a minimum of entries for fixture changes
- Means to expedite and verify correct tube locations, i.e., marked templates
- Television and photographic verification of leak indications and plugged tubes

Improved decontamination techniques may be used if future tube pulling is scheduled, although the decontamination attempt in October 1979 involved considerable radiation exposure and was not successful due to equipment problems.

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UNIT 1 STEAM GENERATOR TUBE PLUGGING HISTORY

Date of Outage	Elapsed Time (Years)	Tubes Plugged: Denting		Thinning or Cracking		Crevice Corrosion		Other		Total		Cumulative Percent	
		A	B	A	B	A	B	A	B	A	B	A	B
12/21/70	0	-	-	-	-	-	-	-	-	1[1]	-	<0.1	0
9/30/72	1.8	-	-	87	91	-	-	14	4[2]	102	95	3.1	2.9
4/6/74	3.3	-	-	1	1	-	-	-	-	103	96	3.2	2.9
2/26/75	4.2	-	-	59	98	-	-	-	-	162	194	5.0	6.0
11/16/75	4.9	-	-	6	4	-	-	-	-	168	198	5.2	6.1
10/1/76	5.8	-	-	-	-	-	-	-	-	168	198	5.2	6.1
6/24/77	6.5	-	-	-	1	-	-	-	-	168	199	5.2	6.1
10/4/77	6.9	10	-	-	-	1	2	-	-	179	201	5.5	6.2
2/1/78	7.1	-	-	-	-	-	-	(3)	-	180	201	5.5	6.2
9/20/78	7.7	1	-	-	-	6	4	-	-	187	205	5.7	6.3
3/1/79	8.2	-	-	-	-	8	1	-	-	195	206	6.0	6.3
8/5/79	8.6	-	-	-	-	52	45	-	-	247	251	7.6	7.7
8/29/79	8.8	-	-	-	-	2	-	3[4]	-	252	251	7.7	7.7
10/5/79	8.9	-	-	-	-	70	64	7	4[5]	329	319	10.1	9.8

Notes:
(1) Plugged during manufacture.
(2) Fourteen tubes in A were plugged due to gouging during machining for clad repair. Three tubes in B were removed for analysis and one was plugged by mistake.
(3) Plugged tube was in periphery.
(4) An audit of tubesheet photographs indicated three tubes which were plugged but previously not included in inspection reports.
(5) Seven tubes in A included three with defects less than the plugging limit, two tubes which had no indications but which were pulled for analysis, and two tubes plugged by mistake. Four tubes in B included three tubes with indications less than the plugging limit and one tube plugged by mistake.

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VIEWGRAPH 2

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UNIT 2 STEAM GENERATOR TUBE PLUGGING HISTORY

Date of Outage	Elapsed Time (Years)	Tubes Plugged: Denting		Thinning or Cracking		Crevice Corrosion		Other		Total		Cumulative Percent	
		A	B	A	B	A	B	A	B	A	B	A	B
8/2/72[1]	0	-	-	-	-	-	-	1	1[3]	1	1	<0.1	<0.1
3/8/73[2]	0.6	-	-	-	-	-	-	-	-	-	-	<0.1	<0.1
10/17/74	2.2	-	-	3	4	-	-	-	-	4	5	0.1	0.1
8/11/75	3.0	-	-	-	3	-	-	-	-	4	8	0.1	0.2
2/26/76	3.6	-	-	14	4	-	-	-	-	18	12	0.6	0.4
3/4/77	4.6	2	-	-	5	-	-	-	-	20	17	0.6	0.5
3/ /78	5.6	-	-	2	-	-	-	-	-	22	17	0.7	0.5
3/ /79	6.6	-	-	-	1	-	-	-	-	22	18	0.7	0.6
Present	7.3	-	-	-	-	-	-	-	-	22	18	0.7	0.6

Notes: (1) 20 percent power operation.

(2) Begin increase to 100 percent power. Achieved in April 1972.

(3) One tube plugged during manufacture and one tube not installed.

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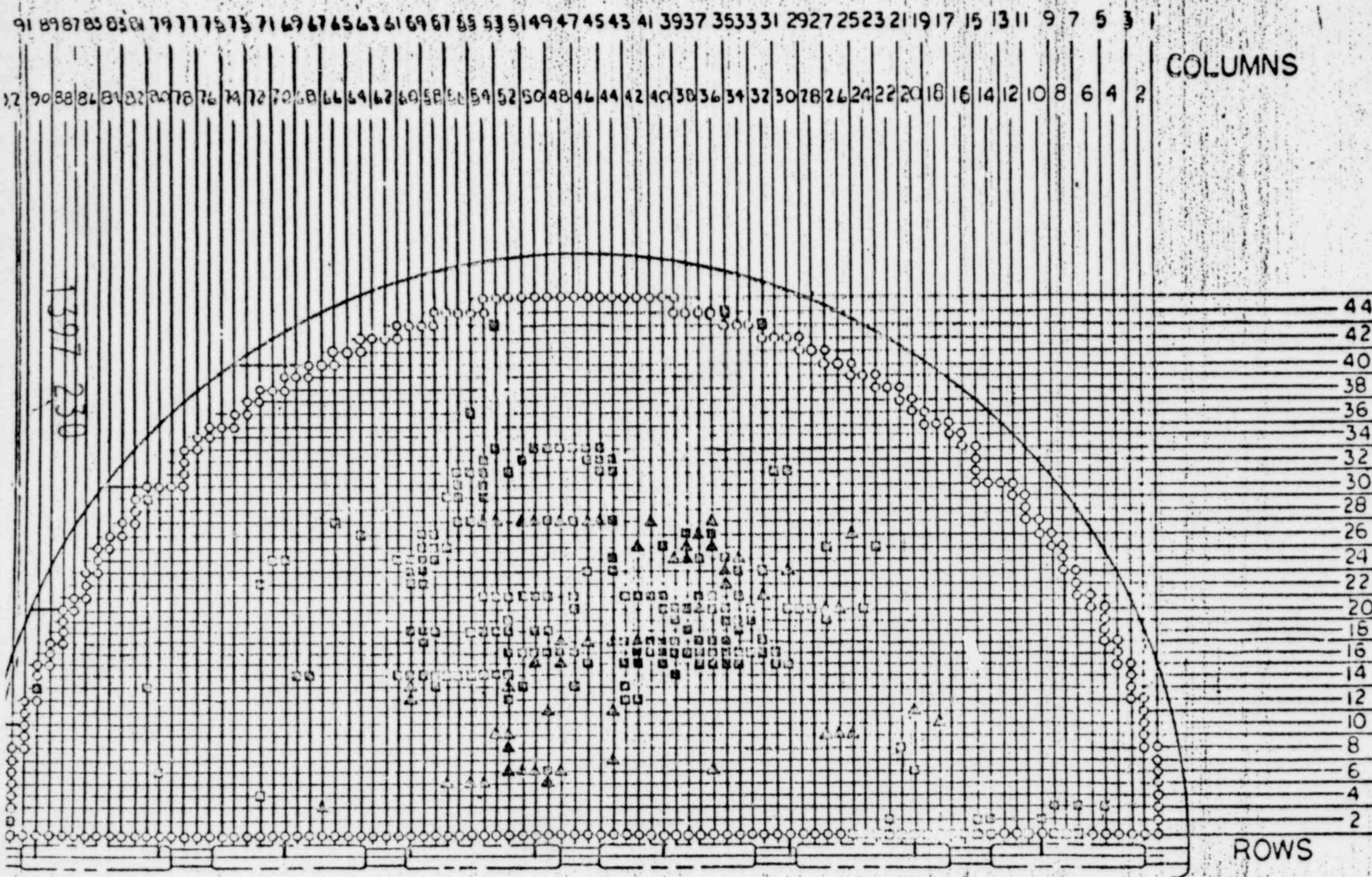
WEP-A

SERIES 44



-MANWAY

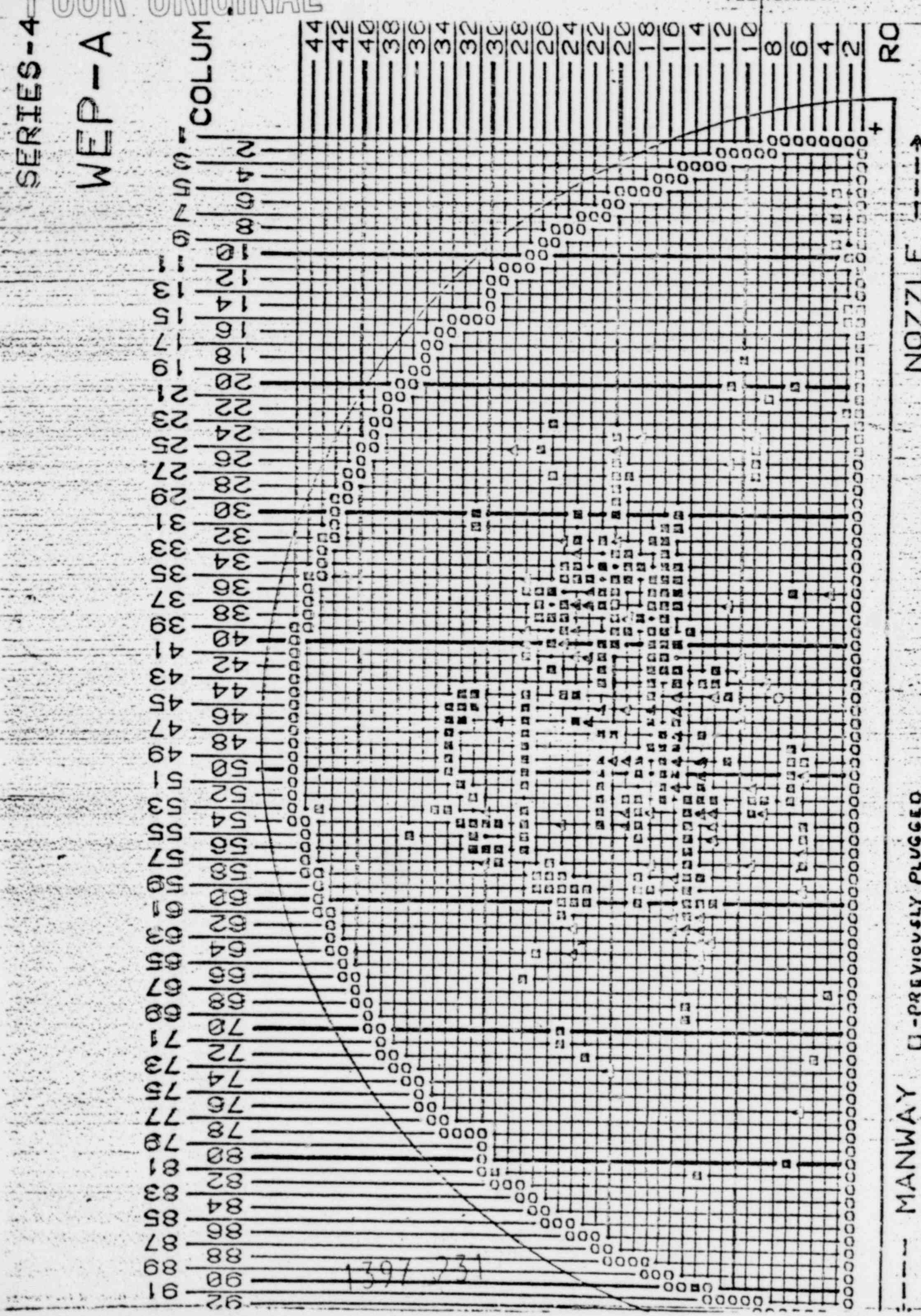
NOZZLE

▢ - PREVIOUSLY PLUGGED

▲ - AUG. 79 PLUGS

POOR ORIGINAL

VIEWGRAPH 3


SERIES-4
WEP-A
COLUMN
ROW
NOZZLE
MANWAY
□-PREVIOUSLY PLUGGED
Δ-Oct 79
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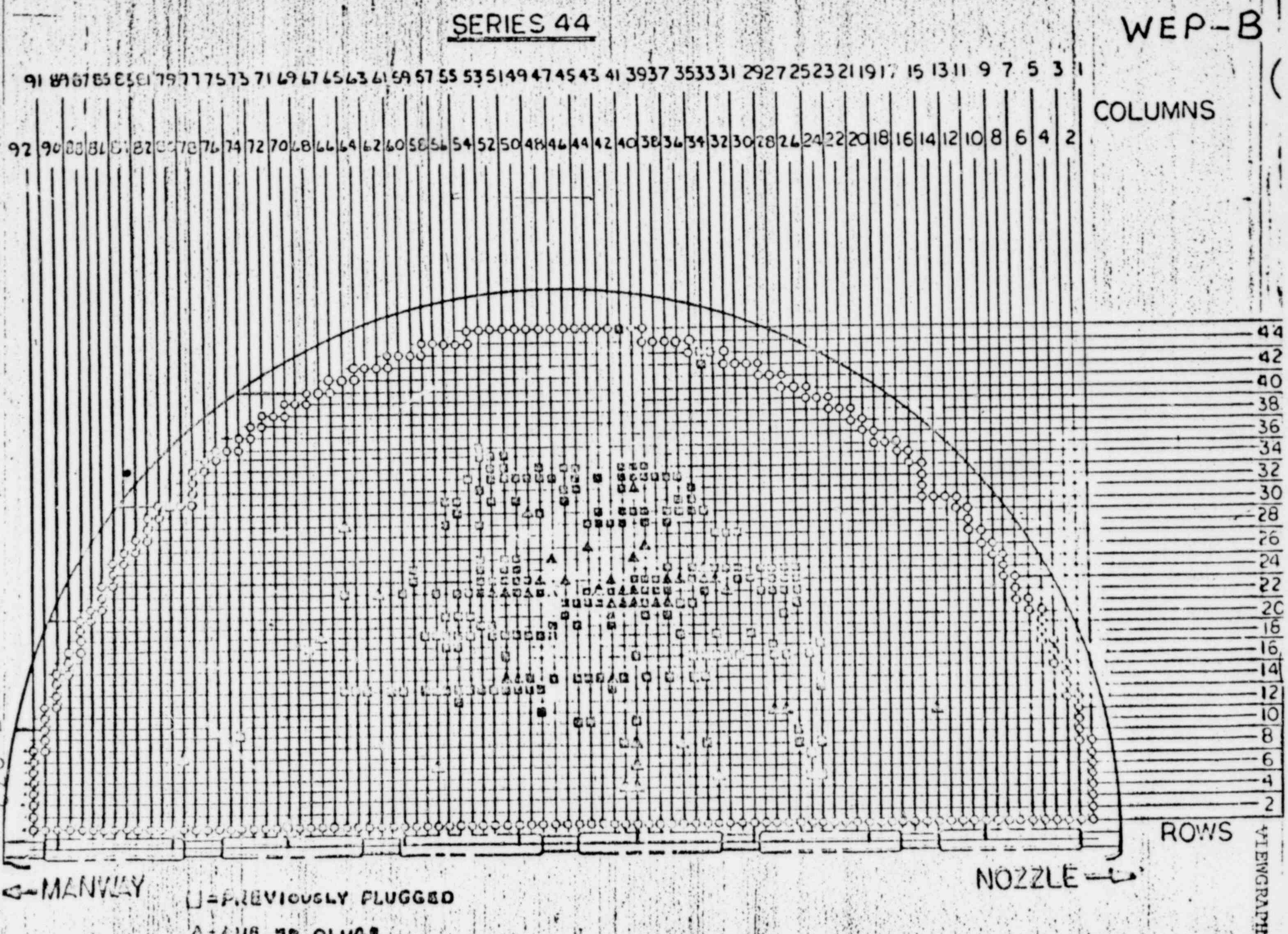
SERIES 4

WEP-B



POOR ORIGINAL

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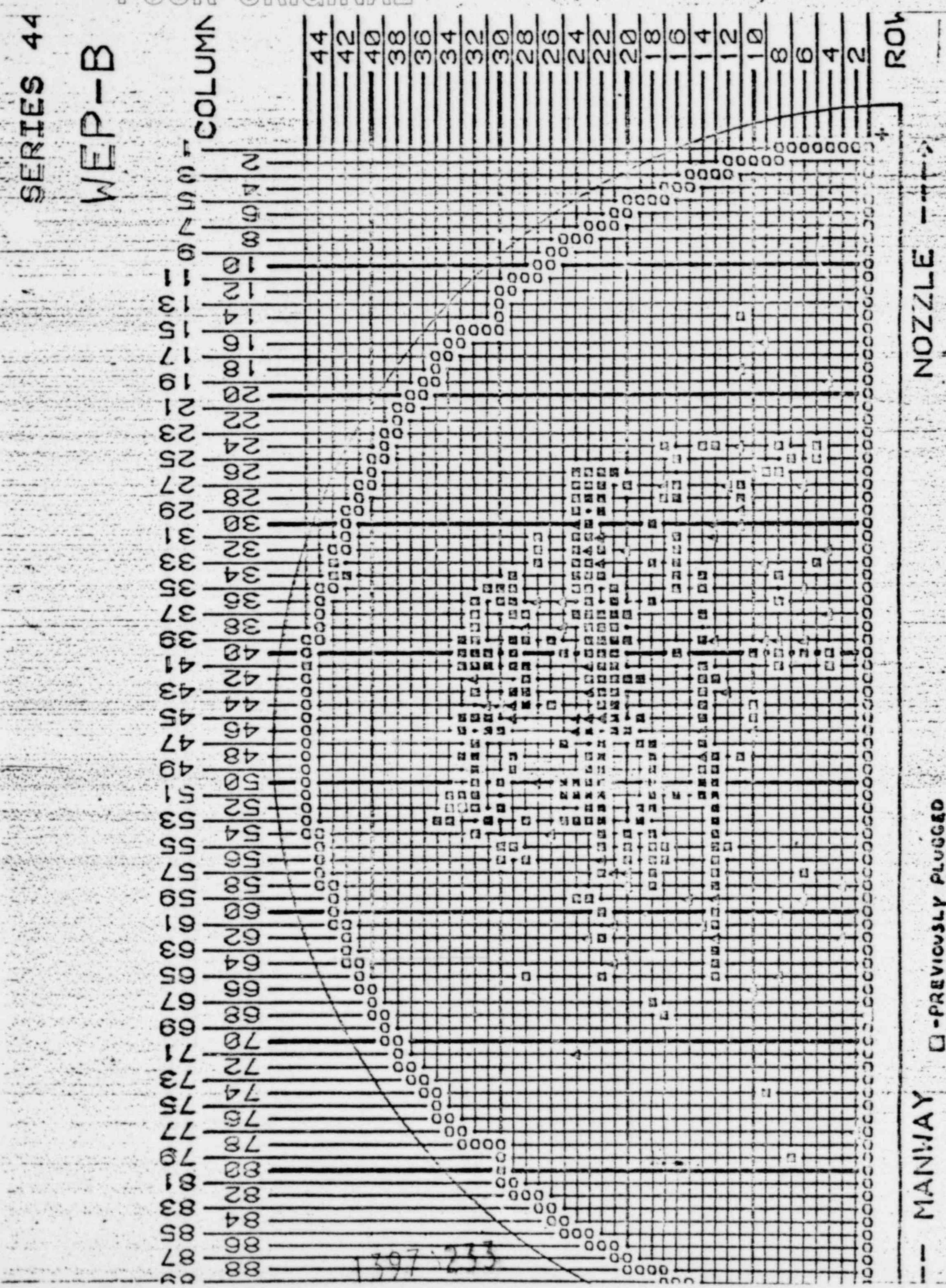
VIEWGRAPH 5

VIEWGRAPH 6



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CREVICE INDICATIONS
AUGUST & OCTOBER OUTAGES
PRELIMINARY DISTRIBUTION
OF INDICATIONS
(PERCENT)

BY DEPTH OF WALL PENETRATION:

	40-49%	50-59%	60-69%	70-79%	80-89%	[illegible]
1A	<1	2.5	3.4	12.1	40.5	40.6
1B	2.6	1.8	8.8	14.1	34.1	44

BY LOCATION IN CREVICE (" FROM TUBE END)

	0-4"	5-9"	10-14"	15-19"	20" to top
1A	0	15.2	16.0	26.4	42.4
1B	3.6	25.2	27.7	21.4	24.1

ENCLOSURE 3

Physical Properties and Testing - Safety Considerations

Three sections of hot leg tubing from A steam generator were removed and sent to the laboratory of the Westinghouse R&D Center in Pittsburgh for detailed investigation of the metallurgical and physical properties and characteristics.

Viewgraph 1 lists the types of investigations that were conducted on the tube samples at the Westinghouse laboratory. Included were eddy current testing (ECT) in the laboratory, radiography, i.e., X-ray of the tube by standard industrial radiographic techniques by the non-destructive test (NDT) group at the labs, metallographic examinations and instrumental microanalyses of the small amounts of materials from the plant that were retained on the surfaces of the pulled tubes. These analyses included the scanning electron microscope (SEM), energy-dispersive analysis of X-ray (EDAX), electron beam microprobe analysis, and an X-ray diffraction pattern determination and species identification of a small powder sample taken from the tube surface. The tube sections were also subjected to extensive mechanical properties testing. The mechanical properties tests will be discussed in detail. The next three viewgraphs show the tube sections that were removed and how and where the various test samples were taken for these examinations.

Viewgraph 2 shows the first tube section that was removed from Row 15, Column 45. Primary flow is upward. About 20-1/2" of tubing were received in five sections, the longest

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of which was a 14-5/8" piece. This long piece extended up to the point where it broke in pulling at a point about 2" below the top of the tubesheet. This tube was extensively examined at many elevations by scanning electron microscopy (SEM), X-ray analysis (EDAX), and by metallography. Three kinds of mechanical properties tests were made; these include a hydraulic pressure test (burst test) on the 5" long section, lead plug load-displacement test on the two 1-inch sections shown, and tensile tests in which stress-strain diagrams were obtained on conventional-geometry sub-size tensile samples that were machined out of the tube at the location shown.

Viewgraph 3 shows the second tube, Row 22 Column 37, from the central region. (It is actually the third tube that was pulled in chronological order.) This tube extended to well above the tubesheet [to just below the first support plate (SP)] and afforded the investigators the opportunity, therefore, to conduct both mechanical properties tests and metallographic examinations of material that was outside of the crevice as well as within the crevice. The upper 5" long section identified for the hydraulic burst test spanned the top of the tubesheet and extended about 2-1/2" above and below this location. A second hydraulic burst test on a 5" sample was conducted on a section from within the crevice. The other mechanical properties tests indicated were the lead plug load-displacement tests, and tensile samples were again machined from samples deep within the crevice. Note that a transverse metallographic cross section was made on a section above the tubesheet immediately adjacent to the upper hydraulic burst sample.

Viewgraph 4 depicts the third tube section, Row 20 Column 73, which was taken from nearer to the periphery of the bundle than the preceding tubes. This tube also extended well above the tubesheet and passed through the first tube support plate. The laboratory investigations included a detailed examination above the tubesheet on a transverse ring 3/4" above the secondary face of the tubesheet, and on a longitudinal 1-1/2" long section, indicated by the short vertical lines, that extended 3/4" above and below the top of the tubesheet. A metallographic examination was also made at a point deep within the crevice, and numerous areas were examined by the microanalytical technique for the composition of materials on the tube surface.

Viewgraph 5 summarizes the results obtained on metallographic examination of all three tube sections. The 15-45 tube that showed an 89 percent in-plant eddy current signal was observed to have cracks through about 90 percent of the wall adjacent to the location of the in-plant signal. This confirms the plant eddy current signal (ECT). This confirmation was also obtained from SEM fractography of the field break which showed that the break was tensile overload ductile-shear due to the large pulling force and that the amount of material remaining to sustain this load was consistent with about 90 percent of the tube having been penetrated by intergranular attack (IGA).

The second tube showed uniform intergranular attack to a depth of about 5 mils within the crevice with IGA occasional deeper crack-like penetrations extending to 50 percent of the wall. No IGA was detected above the tubesheet.

Tube 3 exhibited qualitatively similar features to tube 2 with, again, about 5 miles uniform IGA within the crevice, with fewer penetrations to a depth of 16 mils, or about 33% of the 50-mil wall thickness. Again, no IGA was detected above the tubesheet, and the longitudinal metallographic section that extended 3/4" below the tubesheet showed no IGA along its entire 1-1/2" length.

Viewgraph 6 is a longitudinal metallographic cross section of a section of tube 15-45 taken 3" below the break. This is a macrophotograph of a micro. The OD outer surface is at the top and at the bottom (partially cut off by the printing process) with the tube axis running left-to-right. The ID surfaces are across the wall from the OD surfaces. Note the macroscopically visible penetrations which were torn open from the tube pulling. Note also that macroscopically these extend only about 1/3 of the tube wall and that, macroscopically, the inner approximately 2/3 of the tube wall is unaffected.

Viewgraph 9 depicts the transverse metallographic cross section just above the top of the tubesheet and adjacent to the hydraulic burst sample on the second tube. This location is about 2-1/2" above the secondary face of the tubesheet. In the upper photomicrograph, the full tube wall is seen with the OD at the top and the ID at the bottom. High magnification examination of the OD region, shown in a representative photomicrograph in the lower picture, reveals no IGA.

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Specimens were removed from tubes 15-45 and 22-37 for mechanical tests. Tensile tests, lead plug tests and burst tests were performed. The results indicated that the properties of the base core material which has not seen general intergranular attack is similar to virgin material and that the burst strength of the tubes provides significant margin to resist tube burst during postulated accident conditions.

The tensile specimen size and shape was first described (Viewgraph 13) and the results from the tensile testing described. The results must be interpreted with an understanding of the condition of the tubes prior to tensile testing. The specimens from tube 15-45 were taken from a section of the tube which experienced only small strains during the pulling operation and tube 22-37 specimens were from an area of the tube which saw significant strain induced during the pulling operation on the order of 10 percent. The differences between these two specimens indicate that tube 22-37 specimens saw significant strain hardening which explains the differences in tensile test results. The test specimens T1 to T5 on Viewgraph 14 demonstrate an equivalent engineering strain, including the effect of previous strain hardening, of approximately 30 percent. This magnitude of strain capability is large. The apparent difference between the total strain of the T1 to T5 specimens and the virgin specimen can be explained by understanding that the engineering strain is an average strain over the gage length. The irregularity of the thickness of specimen would indicate that the average strain over the gage length would be less than the virgin material strain

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because of highly localized strain occurring in the attacked specimens. On the basis of the specimen tests and conditions, it is concluded that the remaining core material properties is similar to virgin material properties.

Lead plug tests were run on specimens from tube 15-45. The primary result of use from the lead plug tests is the diametral expansion obtained prior to failure. This data (Viewgraph 15) demonstrates that the tube has sufficient ductility to expand into contact with the tubesheet within the crevice.

Burst tests were performed and are the most important test of those performed. The test results, shown in Viewgraph 16, demonstrate that:

1. Substantial margin to prevent burst exists for the tube in the intergranularly attacked region (maximum pressure applied to the tube during a secondary side pipe break will be approximately 2000 psia); and

2. The difference in burst strength between the specimens from deep in the crevice and that which spans the tubesheet indicates essentially no degradation in burst strength in the region of the tubesheet from a virgin tube burst strength. This coincides with the result of the metallurgical examination which concluded that there was no intergranular attack above this tubesheet.

The next portion of the presentation (Viewgraphs 17 through 20) reviewed the evaluation of various conditions performed for the tubes. Considered were a double ended tube failure during a secondary side pipe break, tube rupture during normal operation and during a secondary side pipe break, and collapse during a LOCA. Tabulated were the required thicknesses of remaining wall in the tube for intergranular attack both inside and outside the tubesheet. These conditions outside the tubesheet were considered for thoroughness and are not indicated as being an existing condition. The tube examination and test specifically indicate that intergranular attack does not exist above the tubesheet. The results of these evaluations indicate that 1) outside the tubesheet, 40 percent of the wall is required to prevent occurrence of the stated conditions*, and 2) inside the tubesheet, the equivalent wall thickness should be 10 percent of the wall and the ductility of the tube must allow expansion of the tube to the tubesheet wall. The conditions of the tubes examined and the test results indicate that these requirements are met.

The condition of cracking both above and below the tubesheet was also evaluated (Viewgraphs 21 and 22). For cracks outside the tubesheet, test results have shown that a tube will leak to a degree which will require plant shutdown prior to rupture of the tube. For cracks inside the tubesheet, either the crack will be deep enough within the tubesheet to prevent it from being pulled out of the tubesheet or the crack will be close enough to the tubesheet such that leak rates will require the plant to be shutdown.

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*Assuming, conservatively, 6 percent tube ovality. 1397 241

The presentation concluded (Viewgraph 23) by summarizing the mechanical test results as indicating that the core of the tube has properties similar to a virgin material and that the burst strength tests showed the limitation of the corrosion to below the tubesheet and the burst strength of the tube spanning the tubesheet as similar to virgin material.

POINT BEACH 1, S/G A

TUBE SAMPLES: W R&D CENTER INVESTIGATION

- LAB ECT
- RADIOGRAPHY
- METALLOGRAPHY
- MICROANALYSES
  - SEM/EDAX
  - ELECTRON BEAM MICROPROBE
  - X-RAY DIFFRACTION
- MECHANICAL PROPERTIES DETERMINATIONS
  - HYDRAULIC PRESSURIZATION
  - LOAD-DISPLACEMENT WITH LEAD PLUGS
  - ST ESS-STRAIN TENSILE TESTS

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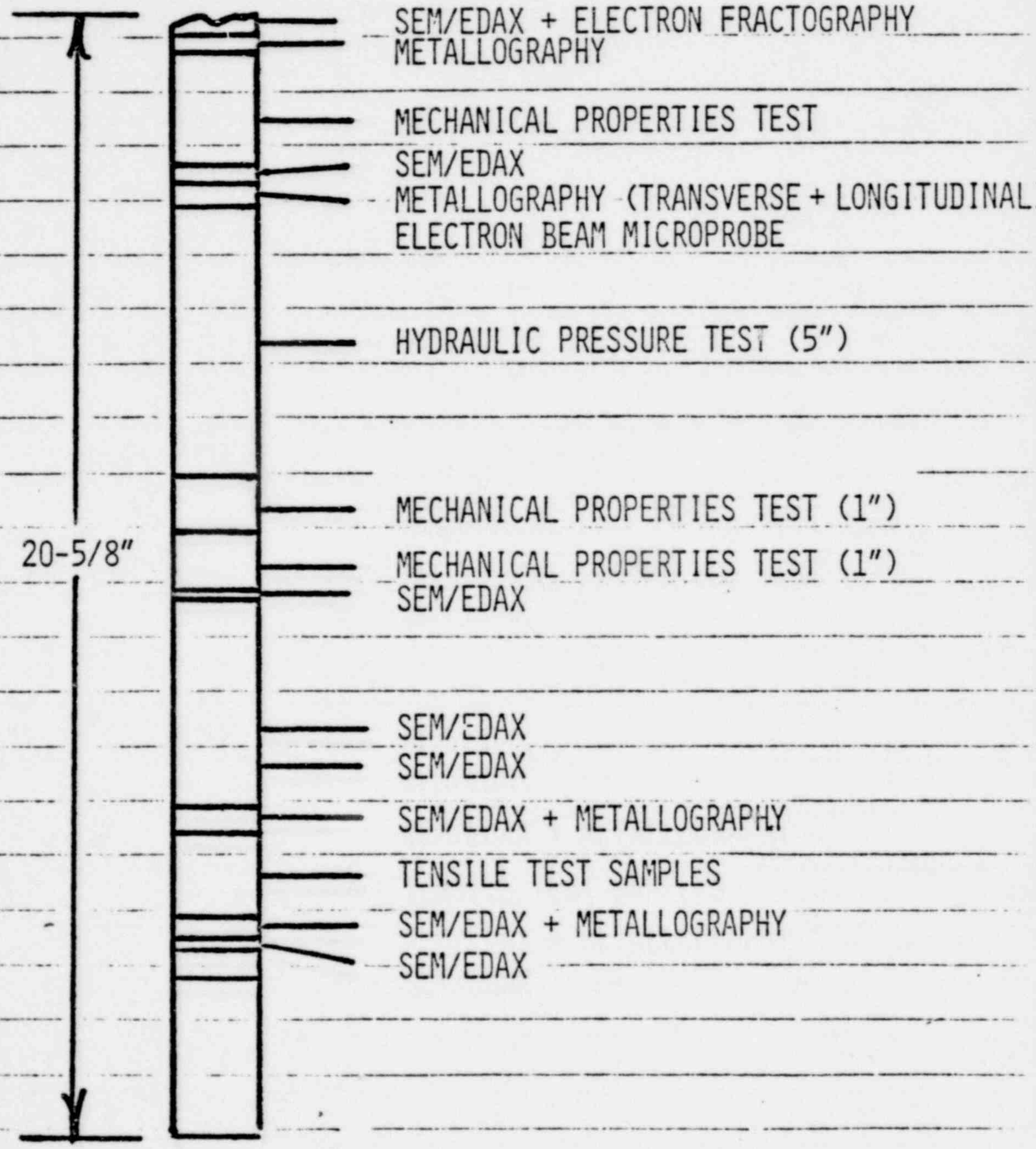
POINT BEACH 1, S/G A, TUBE 15-45, HL

LABORATORY SAMPLES



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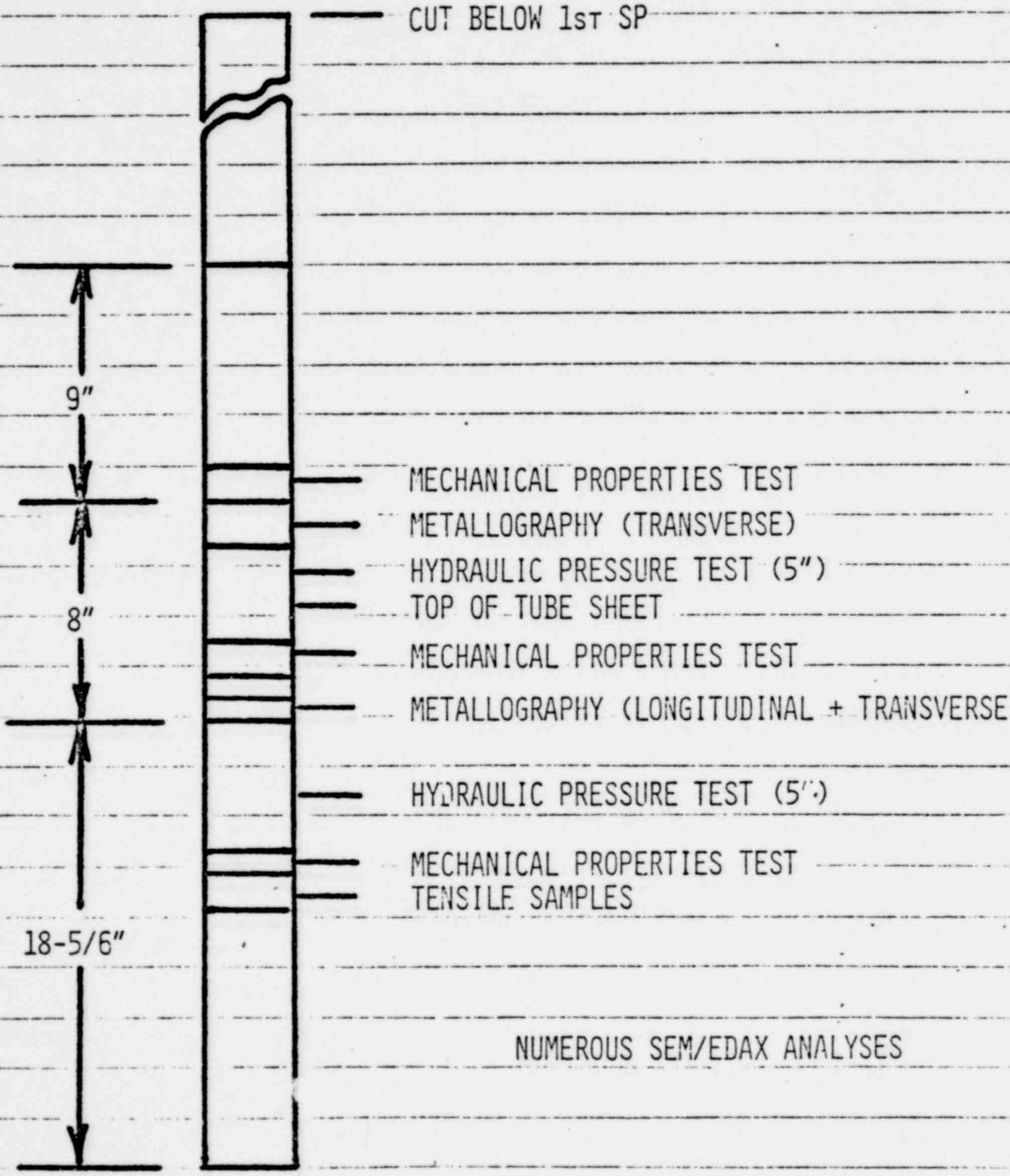
POINT BEACH 1, S/G A, TUBE 22-37, HL

LABORATORY SAMPLES



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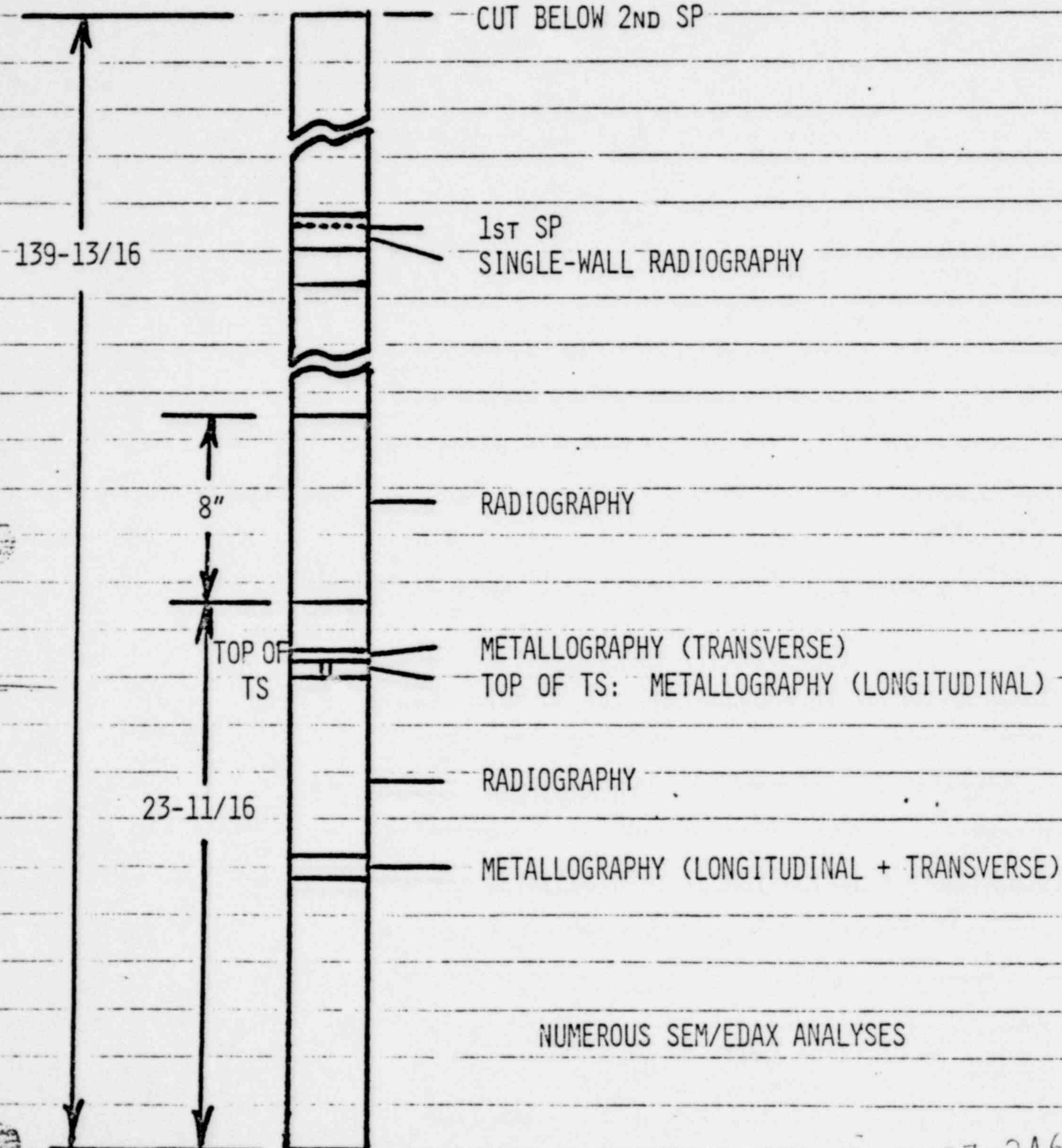
POINT BEACH 1, S/G A, TUBE 20-73, HL

LABORATORY SAMPLES



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POINT BEACH 1, S/G A
METALLOGRAPHY

<u>TUBE A (15-45) (TUBE SHEET ONLY)</u>

- LONGITUDINAL
- TRANSVERSE

IGA: DEPTH CONFIRMS PLANT ECT

<u>TUBE A (22-37) (TUBE SHEET + ABOVE)</u>

- IGA WITHIN TUBE SHEET ~50%
- NO IGA ABOVE TUBE SHEET

<u>TUBE A (20-73) (TUBE SHEET, ABOVE, + 1ST SP)</u>

- SHALLOW IGA WITHIN TUBE SHEET ~33%
- NO IGA ABOVE TUBE SHEET
  - LONGITUDINAL
  - TRANSVERSE

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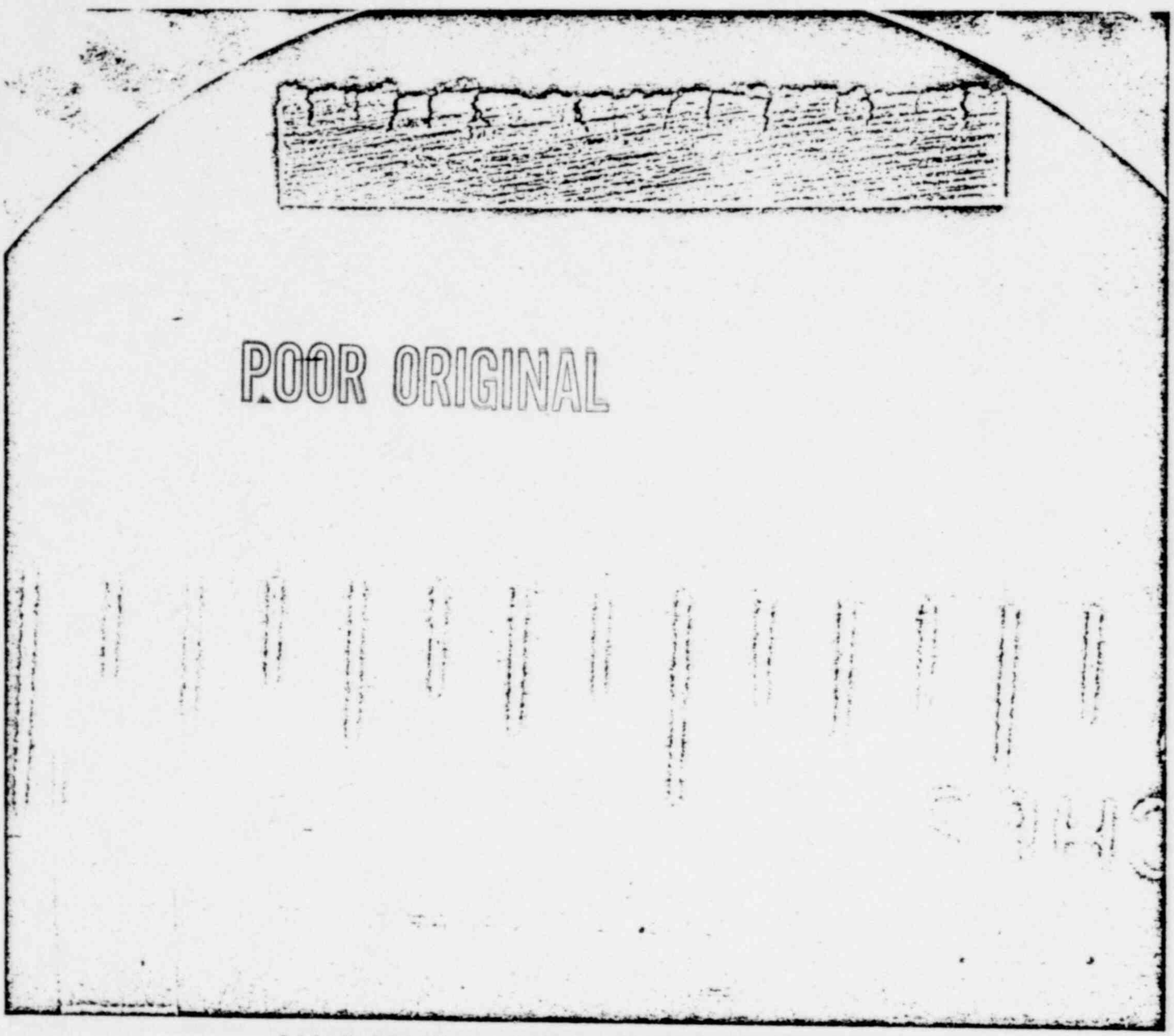
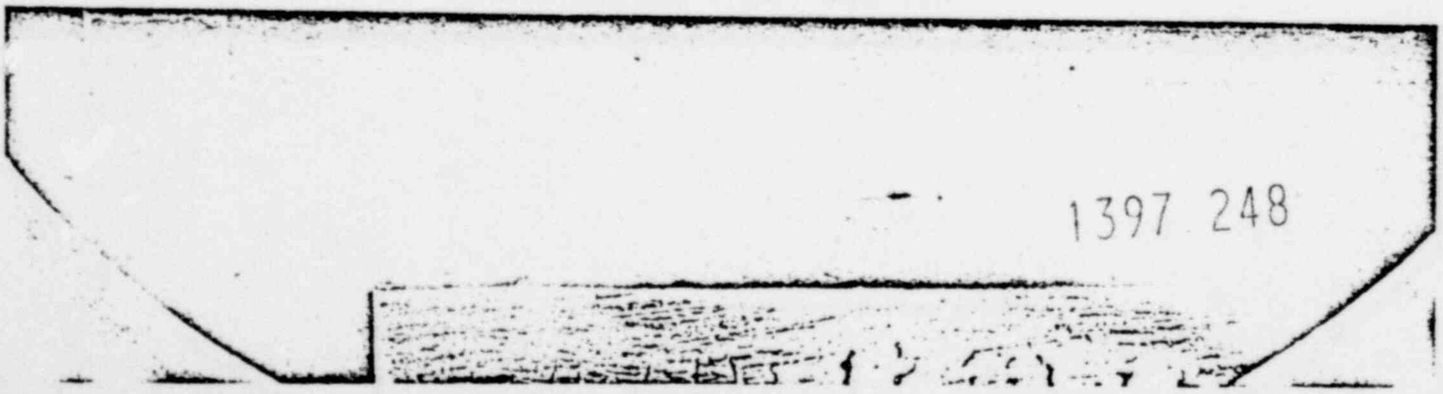
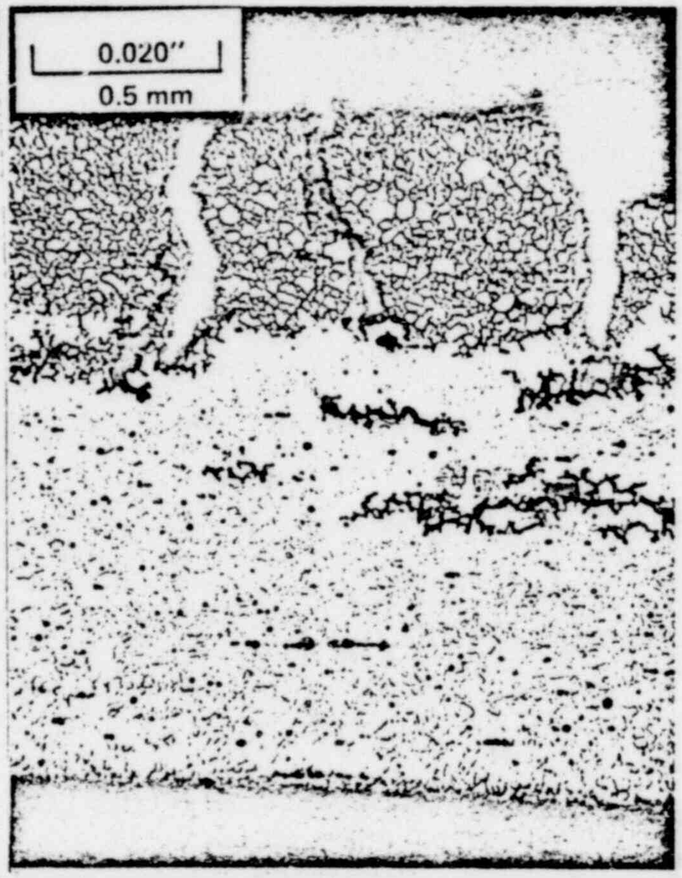


POINT BEACH 1, S/G A, TUBE A 15-45, HL
WITHIN TUBE SHEET: CENTRAL BUNDLE REGION
LONGITUDINAL CROSS SECTION

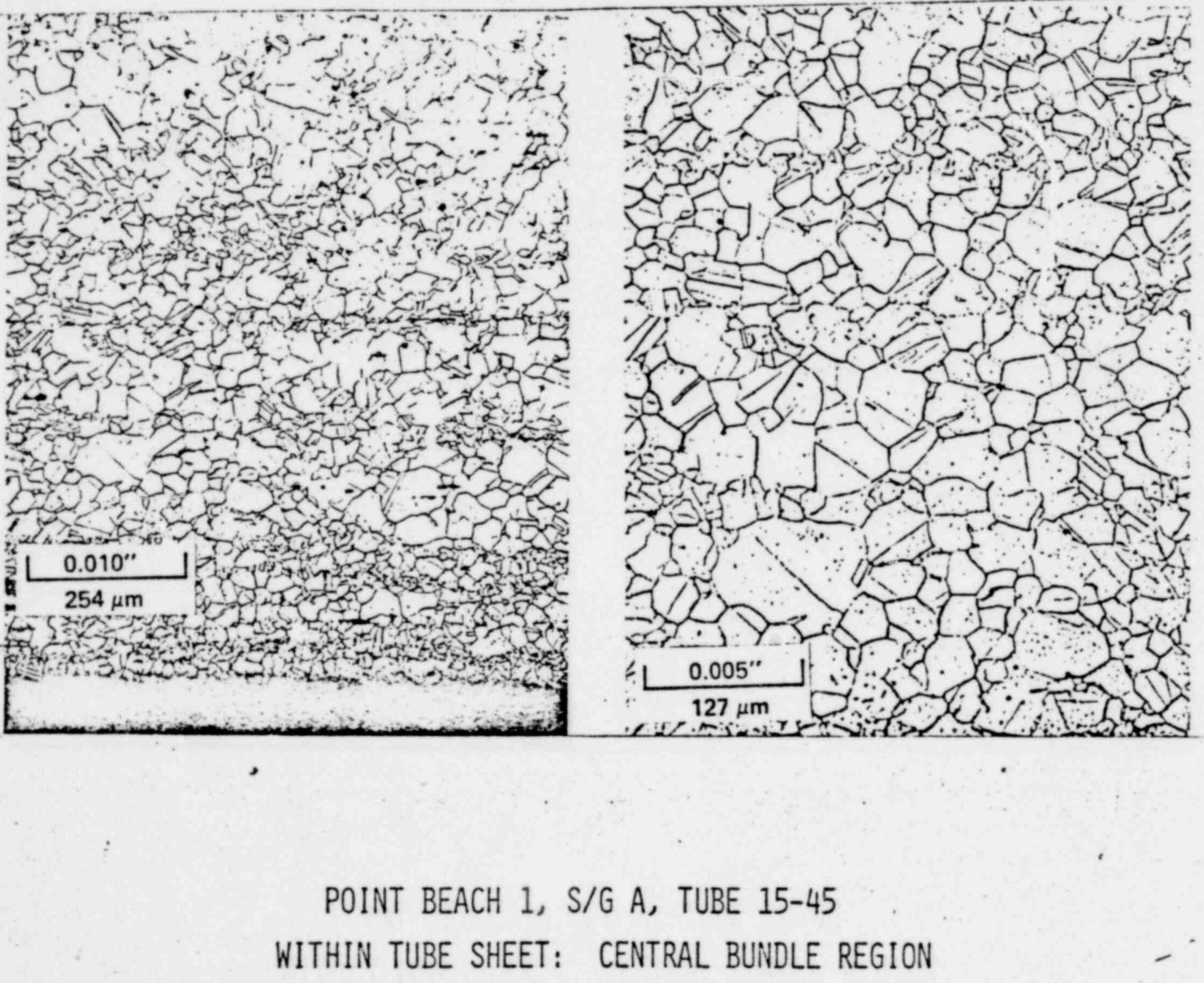




POINT BEACH 1, S/G A, TUBE A 15-45, HL
WITHIN TUBE SHEET: CENTRAL BUNDLE REGION
LONGITUDINAL CROSS SECTION

VIEWGRAPH 8

POOR ORIGINAL



POINT BEACH 1, S/G A, TUBE 15-45

WITHIN TUBE SHEET: CENTRAL BUNDLE REGION

LONGITUDINAL CROSS SECTION

NORMAL INCONEL 600 MICROSTRUCTURE AT ID

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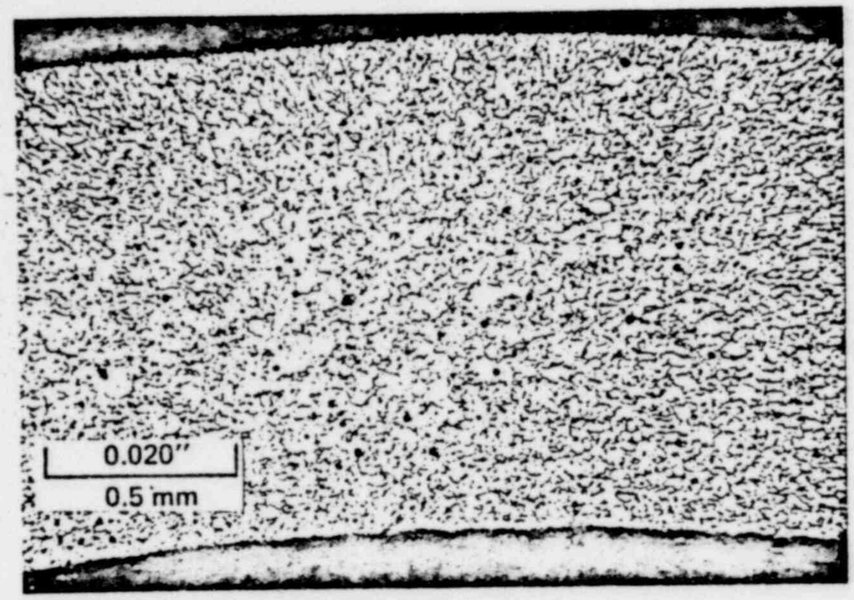
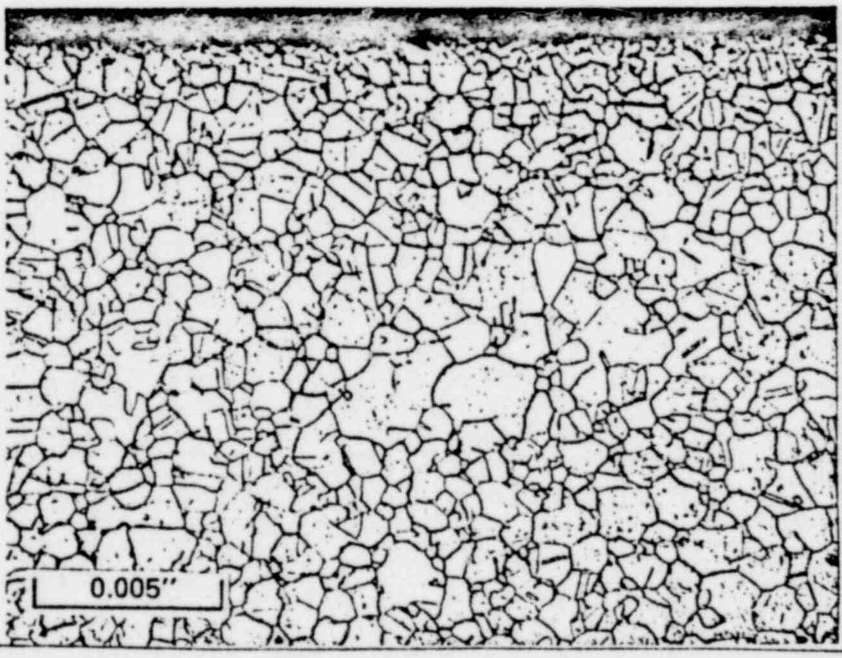
POOR ORIGINAL





POINT BEACH 1, S/G A, TUBE 22-37, HL

ABOVE TUBE SHEET: CENTRAL BUNDLE REGION

TRANSVERSE CROSS SECTION

COMPLETELY FREE OF INTERGRANULAR PENETRATION

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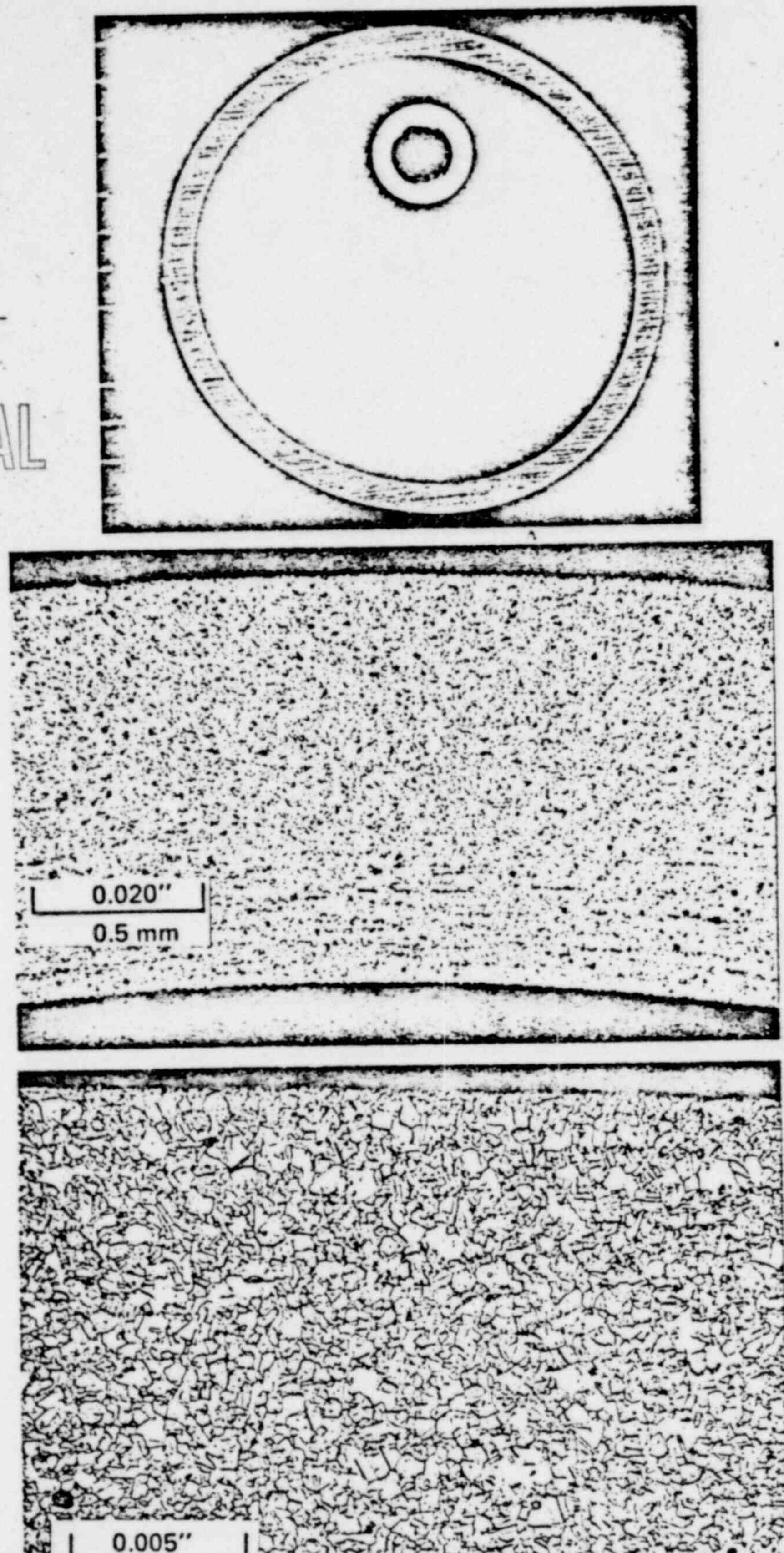

POINT BEACH 1, S/G A, TUBE 20-73, HL

ABOVE TUBE SHEET: PERIPHERAL BUNDLE REGION

TRANSVERSE CROSS SECTION

COMPLETELY FREE OF INTERGRANULAR PENETRATION

POINT BEACH 1, S/G A, TUBE 22-37, HL
FIRST SUPPORT PLATE: CENTRAL BUNDLE REGION

1. LABORATORY EDDY-CURRENT INSPECTION:

   ✓ NO INDICATION

2. LABORATORY "SINGLE-WALL" (HIGH RESOLUTION) RADIOGRAPHY:

   ✓ NO TUBE WALL DEGRADATION

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POINT BEACH 1, S/G A

MICROANALYSES OF OD MATERIALS

- SEM/EDAX
- ELECTRON BEAM MICROPROBE
- X-RAY DIFFRACTION (XRD)

ELEMENTS DETECTED (PROBABLE FORMS)

- Na — Na^{+}
- K — K^{+}
- Ca — Ca^{2+}
- S — SO_4^{2-}
- Al — Al_2O_3, AlO_4^{2-}
- Si — SiO_2, SiO_3^{2-}
- Cl — Cl^{-}

ROUTINE

INFREQUENT

Na_2SO_4 CONFIRMED BY XRD

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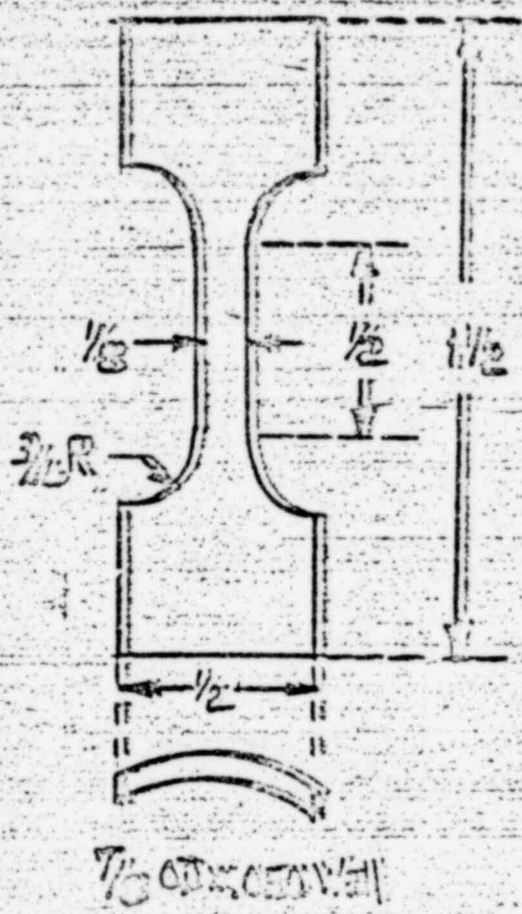
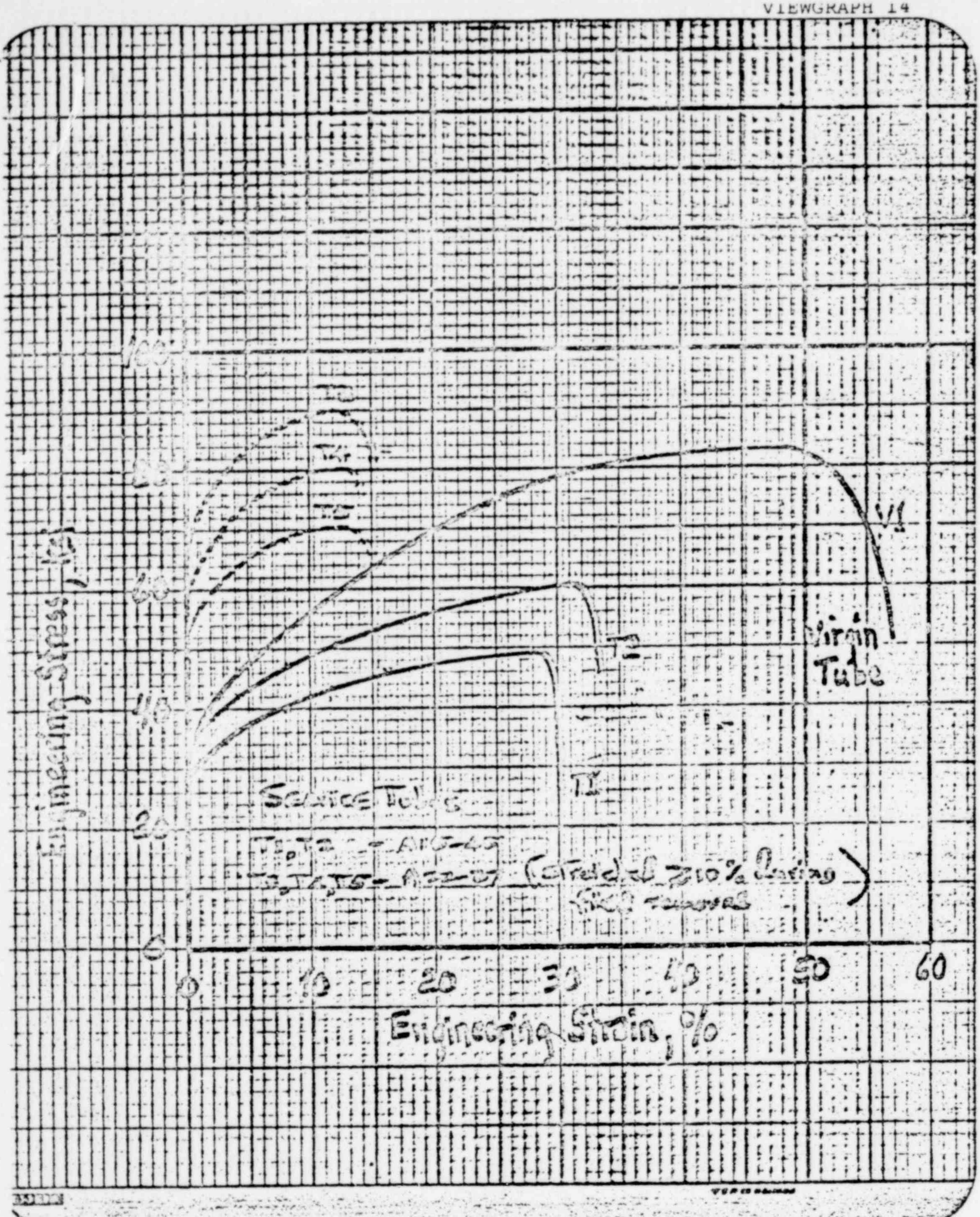


TENSILE SPECIMEN



Engineering Stress, ksi
0
20
40
60
80
100
0
10
20
30
40
50
60
Engineering Strain, %
V1
Virgin Tube
Service Tubes

RESULTS OF LEAD PLUG TESTS ON PULLED TUBE

TEST NUMBER	DIAMETRAL INCREASE
5A66	.045 INCH
5A27	.045 INCH
5B22	.030 INCH

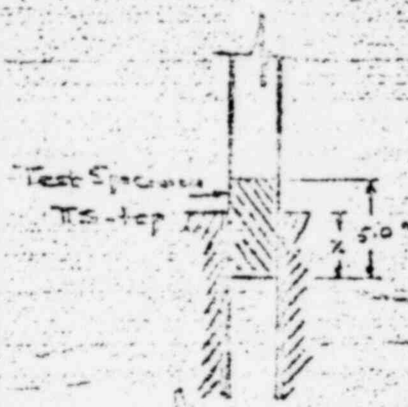
NOMINAL TUBE-TO-TUBESHEET HOLE DIAMETRAL CLEARANCE = .016 INCH

EXPECTED TUBE-TO-TUBESHEET HOLE DIAMETRAL CLEARANCE ZERO

THEREFORE, TUBE WILL BACK-UP AGAINST THE TUBESHEET

RESULTS OF BURST PRESSURE TESTS

TUBE No.	SPECIMEN REGION	BURST PRESSURE
A15-45	x ≈ 12. INCH	5100 PSI
A22-37	x ≃ 10. INCH (SECTION 1D)	6800 PSI
A22-37	x ≃ 2.5 INCH (SECTION 3C)	11,700 PSI*



*PRESSURE DROPPED BECAUSE OF YIELDING. TEST TERMINATED PRIOR TO BURSTING. MEASURED BULGE (DIAMETRAL EXPANSION) AFTER DEPRESSURIZATION ≈ 9.0%.

OBSERVATIONS

- CORROSION IS CONFINED TO THE AREA IN THE TS CREVICE.
- BURST STRENGTH OF TUBE AREA IN THE CREVICE IMMEDIATELY BELOW (AND ABOVE) THE TOP OF TS IS UNAFFECTED, I. E., SAME AS THE VIRGIN TUBE.

POOR ORIGINAL

CONDITIONS EVALUATED

- UNIFORM WASTAGE WITHIN OR OUTSIDE THE TUBESHEET

- CRACKING OF THINNED TUBE WITHIN OR OUTSIDE THE TUBESHEET

- EXAMINATIONS PERFORMED DO NOT INDICATE THAT WASTAGE OR CRACKING EXTENDS ABOVE THE TUBESHEET - THIS CONDITION IS EVALUATED FOR THOROUGH COVERAGE

OUTSIDE THE TUBESHEET

CONDITION	REQUIRED THICKNESS
SAFETY REQUIREMENTS:	
o DOUBLE-ENDED FAILURE DURING SLB	.005 INCH
o TUBE RUPTURE DURING NORMAL OPERATION	.005 INCH
o TUBE RUPTURE DURING SLB	.015 INCH
o NO COLLAPSE DURING LOCA	.020 INCH (6% OVALITY)

WITHIN THE TUBESHEET

CONDITION	REQUIRED THICKNESS
o DOUBLE-ENDED FAILURE DURING SLB	.005 INCH
o TUBE RUPTURE DURING NORMAL OPERATION	°
o TUBE RUPTURE DURING SLB	°
o NO COLLAPSE DURING LOCA	+

°DUCTILITY OF REMAINING MATERIAL MUST ALLOW THE TUBE TO EXPAND TO CONTACT TUBESHEET.

+COLLAPSE WITHIN TUBESHEET NOT POSSIBLE DUE TO CONFINEMENT.

SUMMARY FOR THE UNIFORM WASTAGE CONDITION

REQUIREMENTS:

- MINIMUM TUBE THICKNESS OUTSIDE TUBESHEET MUST BE GREATER THAN .0200 INCH (40% OF WALL)
- EQUIVALENT TUBE THICKNESS INSIDE TUBESHEET MUST BE GREATER THAN .005 INCH (10% OF WALL)
- THE DUCTILITY OF THE TUBE INSIDE THE TUBESHEET MUST ALLOW EXPANSION TO THE TUBESHEET WALL

CONDITION OF THE TUBES EXAMINED AND TESTS PERFORMED INDICATE THAT THESE REQUIREMENTS ARE MET

TUBE INTEGRITY VERIFICATION - CRACKING ABOVE TUBESHEET

- FOR UNSUPPORTED TUBES, GOVERNING CRACK ORIENTATION IS AXIAL
- FOR AXIAL THRU-WALL CRACKS SUPERIMPOSED ON THINNED TUBES, TEST RESULTS INDICATE THE LEAK-BEFORE-BREAK CRITERION IS VALID
- THEREFORE, LEAK RATES WILL REQUIRE PLANT SHUTDOWN PRIOR TO CRACK REACHING CRITICAL LENGTH LEADING TO TUBE BURST

TUBE INTEGRITY VERIFICATION - CRACKING WITHIN TUBESHEET

- LEAK RATE FOR CRACKING WITHIN THE TUBESHEET IS GOVERNED BY ANNULAR GAP

- CIRCUMFERENTIAL CRACK

  - LIMITING CASE - FULL CIRCUMFERENTIAL CRACK

  - FOR BREAKS AT .15 INCH OR BELOW FROM THE TOP OF THE TS, TUBE WILL NOT PULL OUT OF TS DURING A SLB BECAUSE OF TOTAL BUNDLE RESTRAINT

  - FOR BREAKS WITHIN .15 INCH FROM THE TOP OF THE TS, LEAK RATES WILL BE LARGE ENOUGH TO ALLOW DETECTION DURING NORMAL OPERATION

- AXIAL CRACK

  - RESULTS OF LEAD PLUG TESTS INDICATE TUBE HAS SUFFICIENT DUCTILITY TO BACK-UP AGAINST THE TUBESHEET

CONCLUSIONS

MECHANICAL TESTS SHOW:

- PROPERTIES OF UNAFFECTED CORE MAT'L. SIMILAR TO VIRGIN MATERIAL
- BURST TESTS INDICATE THAT CORROSION LIMITED TO TUBESHEET CREVICE
- BURST STRENGTH OF TUBE DIRECTLY ABOVE AND BELOW TS SIMILAR TO VIRGIN MAT'L.

OUTSIDE THE TUBESHEET:

- 40% REMAINING TUBE WALL REQUIRED AND IS INDICATED TO EXIST
- LEAK BEFORE BREAK CRITERIA VALID AND WILL REQUIRE SHUTDOWN PRIOR TO TUBE RUPTURE

INSIDE THE TUBESHEET:

- 10% REMAINING TUBE WALL REQUIRED AND IS INDICATED TO EXIST
- DUCTILITY WILL ALLOW TUBE TO EXPAND TO CONTACT TUBESHEET
- COLLAPSE NOT POSSIBLE DUE TO CONFINEMENT
- LEAKS WITHIN TS WILL EITHER BE DEEP ENOUGH THAT THE TUBE CANNOT PULL OUT OR LEAKAGE WILL REQUIRE SHUTDOWN

ENCLOSURE 4

Accident Analysis

Table 1 summarizes the presently licensed mode of operation as well as the expected mode of operation at reduced pressure and temperature. Should Unit 1 operate at only reduced pressure, the normal operating conditions would be the same except that the Plant would be operating at 2,000 psia. When Unit 1 is operated at reduced temperature, secondary pressure decreases, reducing the Unit's electrical output due to the maximum flow capability of the turbine with valves wide open. With a hot leg temperature of approximately 557°F, it is estimated that the unit output will be 83% of full power. At the low temperature condition, the expected core inlet temperature will be 510°F.

Table 2 describes the approved Point Beach LOCA analysis. Table 3 summarize the effect on peak clad temperature for changes in the number of steam generator tubes plugged and a reduction in primary system pressure. LOCA results at various operating conditions are listed in Table 4. Four cases are presented. Case One is the ECCS analysis presently approved by the NRC with 10 percent of the steam generator tubes plugged. Case 2 represents the case recently filed, with 18 percent of the tubes plugged and at normal reactor coolant system pressure and temperature. Case 3 shows the sensitivity to the reduction in primary system pressure to 2,000 psia with 18 percent of the steam generator tubes plugged. Case 4 is provided for information to show the margin available when operating at the expected

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conditions of reduced pressure, temperature, and the resulting 83 percent power level. All of the peak clad temperatures given on this Table include the addition of 60°F for upper plenum injection as can be seen in the results. All the possible operating conditions meet the requirements of 10 CFR Part 50.46 of the Commission's Regulations.

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POINT BEACH OPERATING CONDITIONS

NORMAL OPERATION

POWER LEVEL	100%
PRIMARY SYSTEM PRESSURE	2,250 PSIA
HOT LEG TEMPERATURE	598°F
COLD LEG TEMPERATURE	542°F
LOOP TEMPERATURE DIFFERENCE	56°F
AVERAGE TEMPERATURE	570°F
SECONDARY PRESSURE	800 PSIA

LOW PRESSURE AND TEMPERATURE OPERATION

POWER LEVEL	83%
PRIMARY SYSTEM PRESSURE	2,000 PSIA
HOT LEG TEMPERATURE	557.3°F
COLD LEG TEMPERATURE	510.0°F
LOOP TEMPERATURE DIFFERENCE	47.3°F
AVERAGE TEMPERATURE	533.6°F
SECONDARY PRESSURE	600 PSIA

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TABLE 2

CURRENTLY APPROVED POINT

BEACH LOCA ANALYSES

I) PERFORMED WITH THE CURRENTLY APPROVED WESTINGHOUSE EVALUATION MODEL (FEBRUARY 1978 MODEL)

II) ANALYSES ACCOUNTED FOR 10 PERCENT TUBE PLUGGING

RESULTS:

(1) PCT = 2067^{o}F

(2) PEAKING FACTOR = 2.32

(3) MARGIN TO 2200^{o}F IS 133^{o}F

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TABLE 3

RECENT CHANGES AT POINT BEACH
WHICH IMPACT LOCA ANALYSES

I) INCREASED TUBE PLUGGING

A) INCREASED FROM 10% TO 18%

B) SENSITIVITY OF APPROXIMATELY 6°F/1% T.P.

C) ΔPCT = +48°F

II) REDUCED PRIMARY PRESSURE

A) REDUCED FROM 2280 TO 2000 PSIA

B) SENSITIVITY OF APPROXIMATELY 2.85°F/100 PSIA

C) ΔPCT = 8°F

III) REDUCED PRIMARY PRESSURE + TEMPERATURE

A) REDUCED COLD LEG TEMPERATURE FROM 544°F TO 510°F

B) REDUCED POWER BY 17%

C. SENSITIVITY: REDUCED PCT BY 290°F

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TABLE 4

LOCA RESULTS AT VARIOUS OPERATING CONDITIONS FOR POINT BEACH

PARAMETER	CASE 1	CASE 2	CASE 3	CASE 4
POWER	100%	100%	100%	83%
% TUBE PLUGGING	10	18	18	18
RCS PRESSURE	2280	2280	2000	2000
TCOLD	540	544	544	510
PSEC	771	799	799	580
FQ	2.32	2.32	2.32	2.32
PCT	2067	2113	2121	1830
ELEVATION	7.5	7.5	7.5	7.5

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ENCLOSURE 5

Actions to Minimize Degradation and To Assure Safety

A crevice-flushing technique has been developed to attempt to remove soluble materials from tubesheet crevices and thereby to aid in minimizing or arresting further degradation of tubes in the crevices. This procedure, Viewgraph 1, involves the following steps:

1. Fill steam generators to one to two feet with demineralized water or condensate.
2. Heat up to 250°F with reactor coolant pumps and with main steam stop valves closed.
3. Hold for one hour to dissolve material in crevices.
4. Subcool water in the steam generators by adding demineralized water or condensate.
5. Depressurize with the atmospheric steam dump valves. This should cause the solution in the crevices to flash and be forced out by the flashed steam.
6. Cool to about 200°F by cooling the primary system. This will collapse the steam in the crevices which, in turn, refills the crevices with water.
7. Drain the steam generators.

Viewgraph 2 provides the preliminary results of the use of this procedure for Unit 1 steam generators. As shown in the viewgraph, 14 cycles were performed and several pounds of sodium and phosphate were removed from each of the steam generators. Since there are two possible sources of soluble sodium and phosphate in the steam generators (crevices and residual sludge) attempts were made to define the removal of material from the crevices by sampling prior to the depressurization step and

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and performing a materials balance. These calculations indicate approximately 33 and 38 percent of the total materials removed were from the crevices in steam generators A and B, respectively. Further evaluations of these data will be performed.

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POINT BEACH UNIT 1

CREVICE-FLUSHING PROCEDURE

1. Fill steam generator to 1 to 2 feet.
2. Heat up to 250°F.
3. Hold for about one hour.
4. Subcool water on tubesheet.
5. Depressurize with atmospheric steam dumps.
   Crevice solution flahses.
6. Cool primary system to 200°F crevice steam collapses.
7. Drain and refill.

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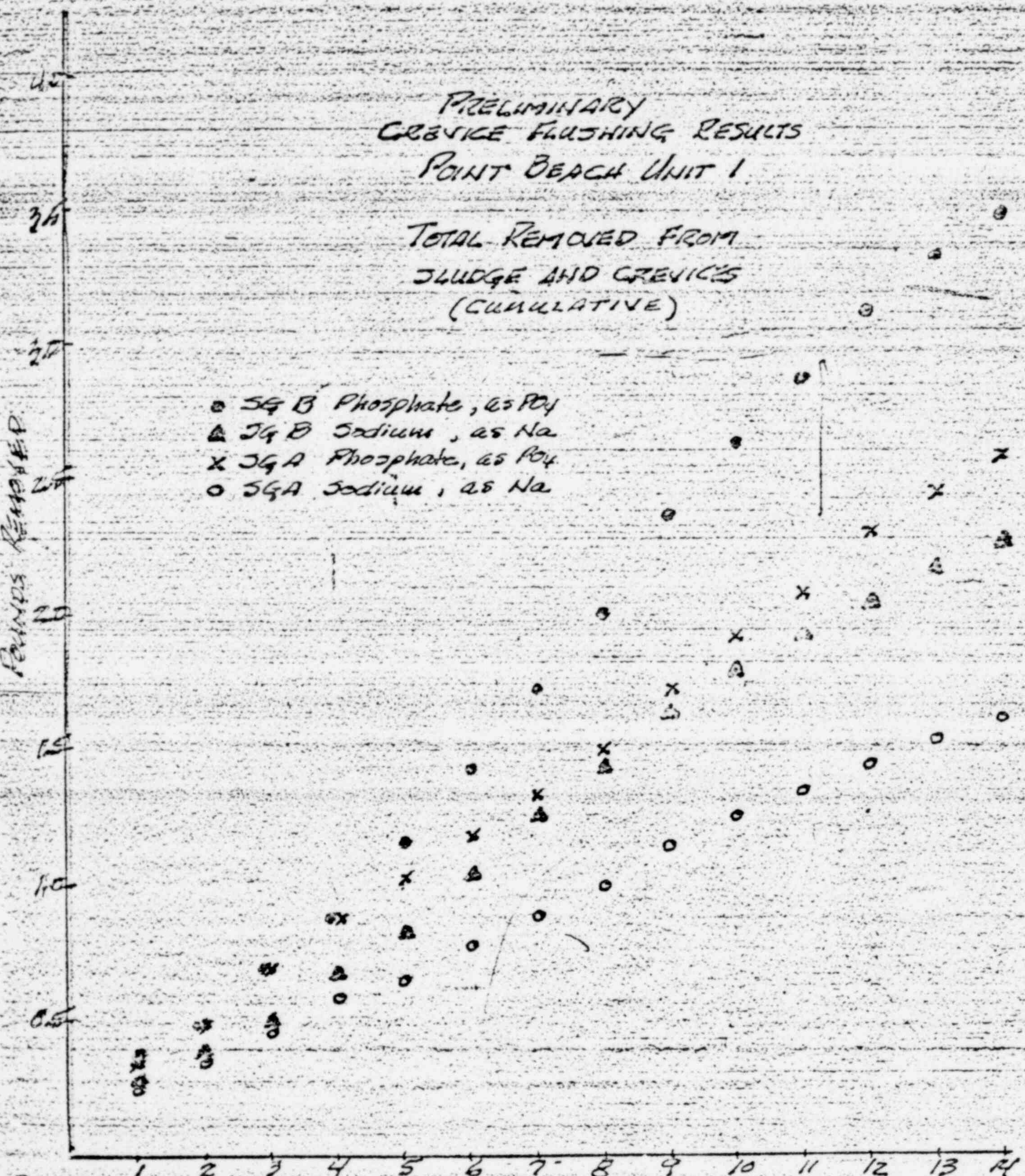
POOR ORIGINAL



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Hydrostatic pressure tests were performed after completing tube inspections and plugging. An 800 psi secondary to primary pressure test was successfully conducted in November 1979 to verify zero tube leakage and the capability of the unit to withstand the maximum LOCA. On November 20, 1979, a 2000 psi primary to secondary differential pressure test was successfully applied to Unit 1 to demonstrate its capability to withstand without tube failure a main steam line or feed line break.

On return to service, it is planned to conduct a primary to secondary differential pressure test in approximately 30 days and to repair any leakage detected. If no leakage is found, this primary to secondary differential pressure test will be repeated in 60-90 days.

A Technical Specification eddy current examination of both Unit 1 steam generator tubes will be performed not later than one year from return of the unit to service, unless required sooner by tube leakage or plugging experience. A 100% eddy current examination was conducted in October-November 1979.

On return to service, monitoring of plant chemistry will be rigorously followed. Primary to secondary leakage will be closely monitored with the following limits requiring immediate plant shutdown:

1. Sudden primary-secondary leakage of 150 gpd (0.10 gpm) or greater.
2. Any primary-secondary leakage exceeding 250 gpd (0.17 gpm).
3. Increase in rate of primary-secondary leakage of greater than 15 gpd per day (0.01 gpm) if the total leak rate exceeds 150 gpd.

Present Technical Specification limits are 500 gpd (0.35 gpm).

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The intergranular corrosive attack observed in the tube sheet crevice area of steam generator tube sections removed from the Point Beach 1 plant is indicative of caustic stress corrosion cracking. Microanalysis of deposits on the affected sections also show the presence of alkaline forming species.

Laboratory studies show that there is a significant temperature dependence of caustic stress corrosion cracking as illustrated in Figures A and B. These results are for pressurized capsules exposed to 10% and 50% NaOH at varying stresses at temperatures ranging from 650 to 550°F. As can be seen, reducing the temperature below 600°F significantly extends the time for SCC to occur. This temperature dependence is further illustrated in Figure C where temperature is plotted versus rate constant for both 10% and 50% NaOH.[1] The rate constant is developed from a linear crack growth rate law:

$$\frac{dl}{dt} = kt$$

l = Crack length

t = Time

k = Rate constant

$$dl = kt\ dt$$

$$l_t = l_o + \frac{k}{2} t^2$$

$$k = \frac{2(l_t - l_o)}{t^2} = k_o l^{-\Delta H/RT}$$

If $l_o <<< l_t$

Plot log K versus 1/T

(1) This plot is based upon the time to develop a 3 mil crack in mill annealed Inconel 600 at 30 ksi in 10% and 50% NaOH solutions.

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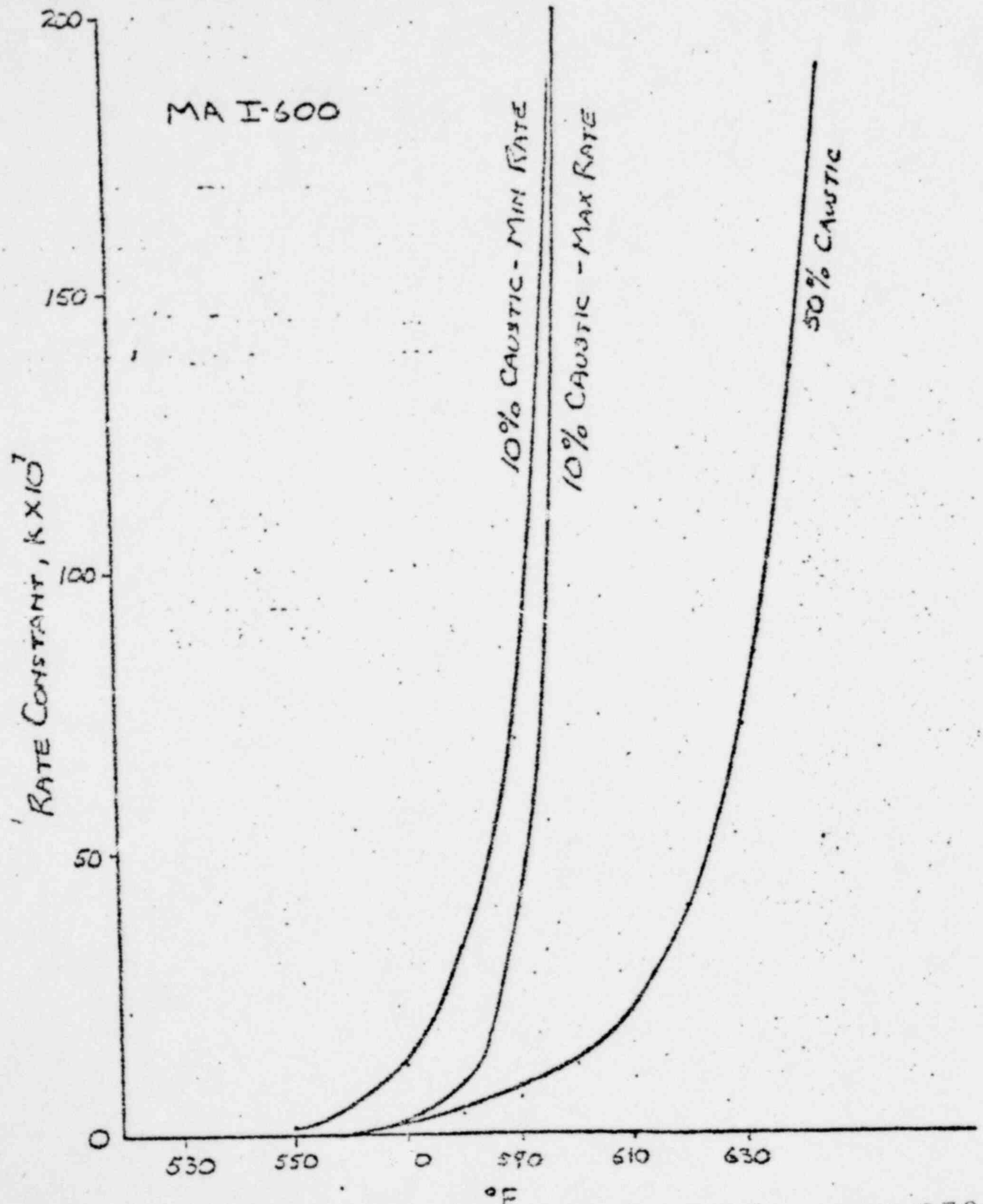
Indicated Variation in Rate of SCC
With Temperature



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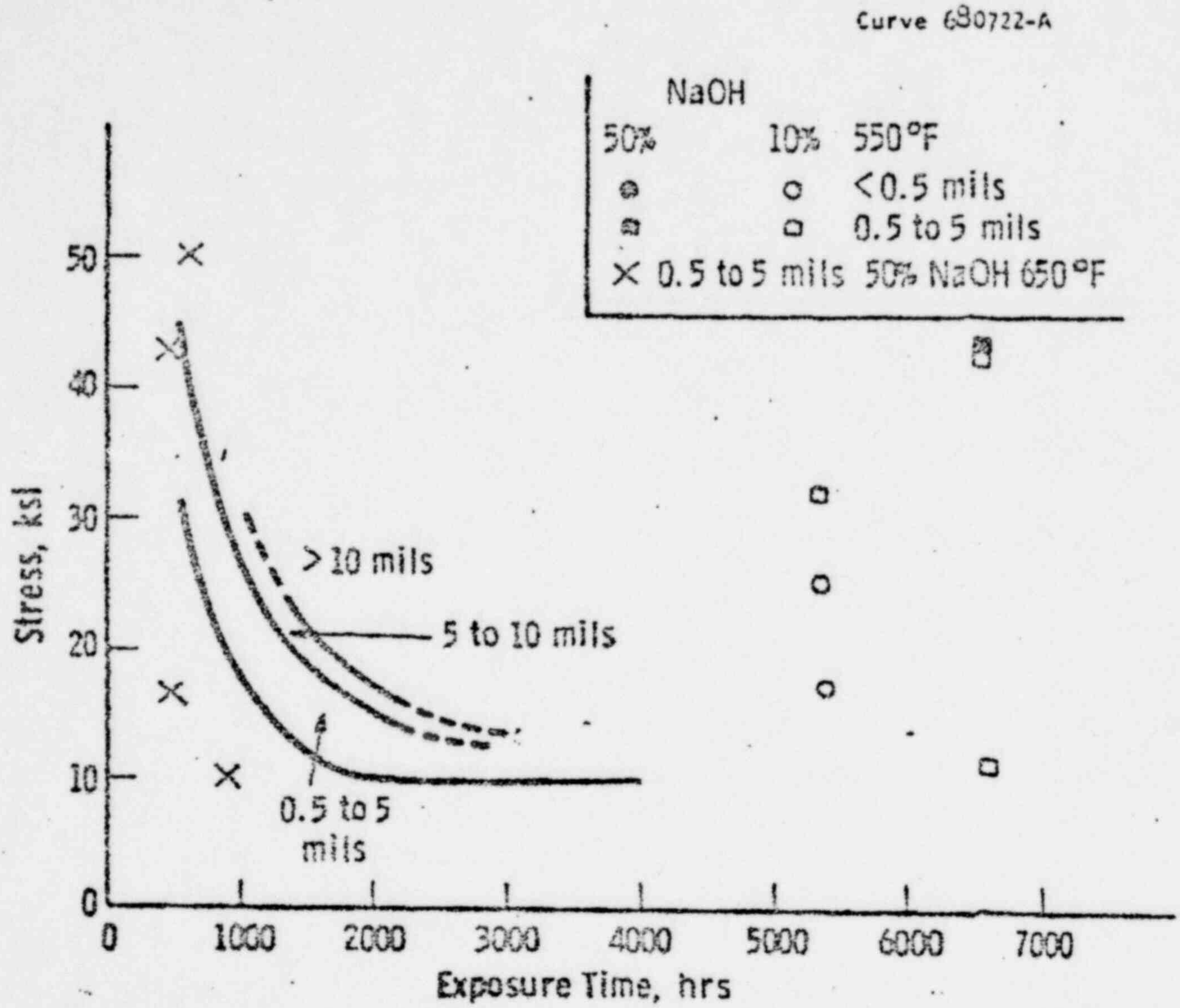

Fig. 10—Caustic cracking of mill annealed alloy 600 at 550°F and 650°F (Lines depict zones of crack depth from 10% NaOH at 600°F)

POOR ORIGINAL

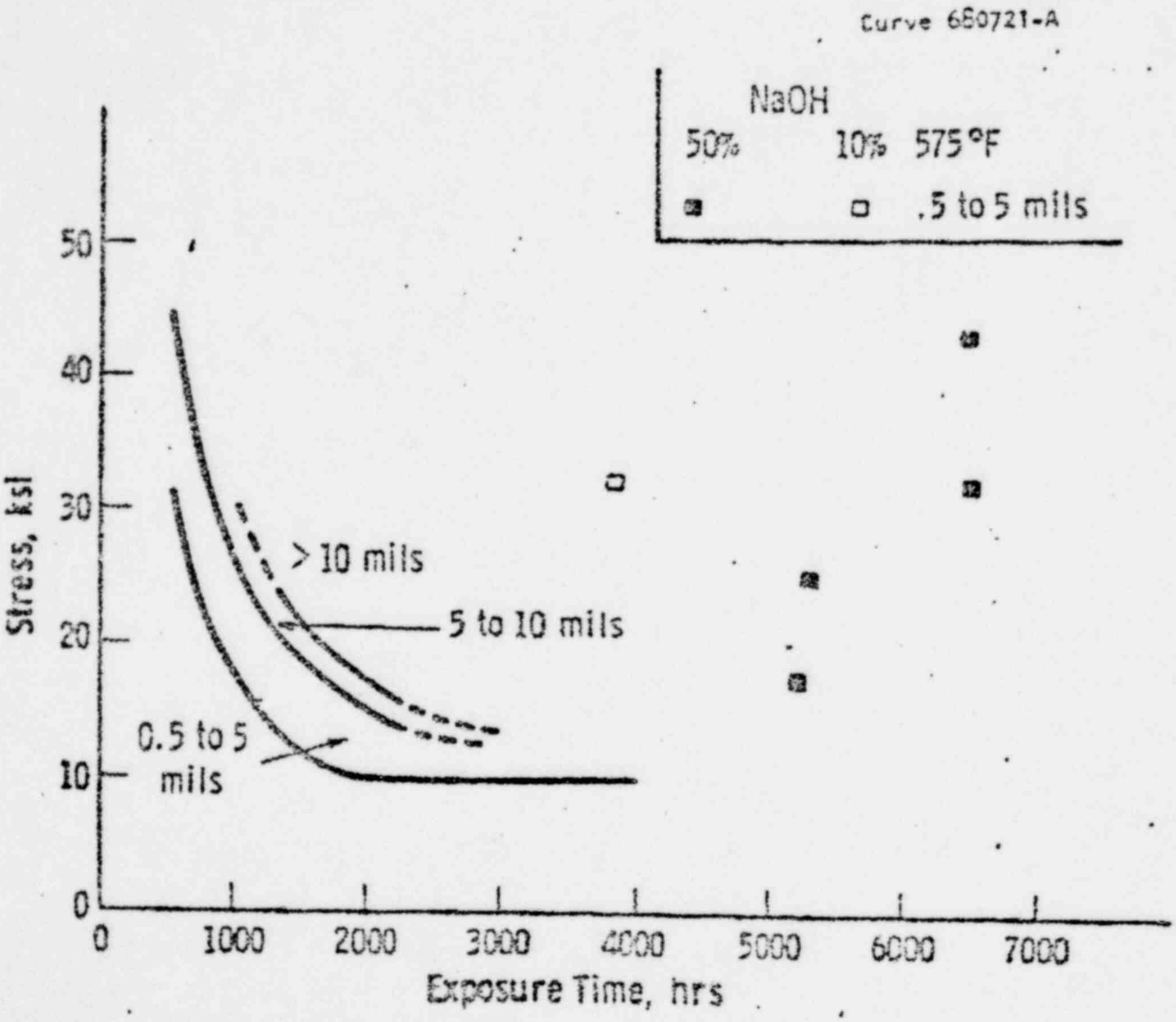

Fig. 9—Caustic cracking of mill annealed alloy 600 at 575 °F (Lines depict zones of crack depth from 10% NaOH at 600 °F)

POOR ORIGINAL

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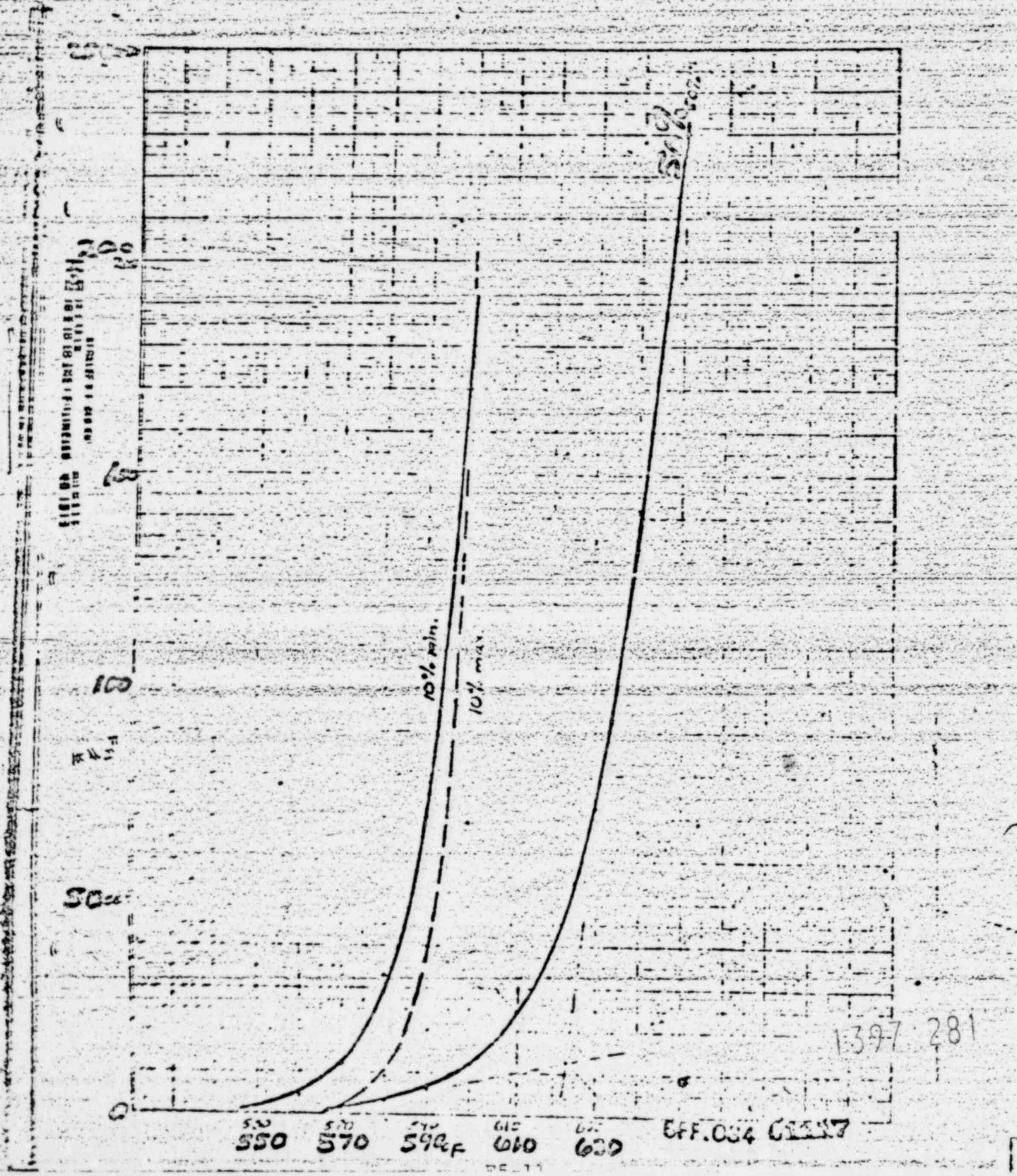
POOR ORIGINAL



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In addition to the foregoing actions, Licensees are investigating longer term solutions, including sleeving, retubing in place, and replacement of the steam generator lower assemblies or the entire steam generator units.

On the basis of these data and on the basis of the Point Beach Unit 1 experience wherein no crevice corrosion failures have occurred on the cold leg side of the steam generators, it is planned to return Unit 1 to service at reduced operating temperatures of 575°F T_H and 510°F T_C.

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