DUKE POWER COMPANY
OCONEE NUCLEAR STATION

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STEAM GENERATOR TUBE LEAK
STATUS REPORT

August 26, 1977

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STEAM GENERATOR REPORT

1.0 INTRODUCTION

Experience with the Babcock and Wilcox designed Once Through Steam Generators (OTSG) at the Oconee Nuclear Station has been complicated during the last year by the occurrence of eleven tube leaks in four of the six steam generators. Initially, the first leak in July, 1976 was considered to have resulted from a random manufacturing defect; however, with successive leaks it became apparent that a significant operational problem existed. A program of systematic investigation was jointly initiated by B&W and Duke to determine the possible cause of these failures and to develop corrective actions to reduce the frequency of the leaks. This report documents those efforts which have been and will be expended to resolve this problem.

Section 2 of the report provides a history of operation of the once through steam generators and the sequence of steam generator tube leaks and investigations performed. Section 3 provides a description of those evaluations which have been performed and their results. It should be noted that the majority of these investigations have not revealed a singular cause of the tube failure; however, these evaluations have been useful in systematically disproving each hypothesized failure mechanism. Those corrective measures which have been taken to possibly reduce the frequency of leaks are also described. Section 4 describes those future plans for resolution of the steam generator tube problem. These plans include site activities, analyses and laboratory testing, field instrumentation programs and design modification development.

It is the goal of this investigative program to identify and implement those corrective actions which will reduce the frequency of leaks to an acceptable level. It should also be recognized, however, that a single/specific cause for the observed tube leaks may not be determinable.

2.0 HISTORY

The Oconee Nuclear Station consists of three essentially identical units utilizing Babcock and Wilcox nuclear steam supply systems. The three units received NRC Facility Operating Licenses on February 6, 1973, October 6, 1973, and July 19, 1974 respectively. This NSSS utilizes two once-through-steam-generators (OTSG) of the straight tube design. Each OTSG (designated A and B) consists of approximately 15,500 5/8 inch OD Alloy 600 tubes contained in a cylindrical steel shell 56 feet high. The tubes are supported by an upper and lower tubesheet, to which the tubes are welded, as well as 15 tube support plates arranged at approximately 3 foot intervals between the upper and lower tubesheets. The general arrangement is indicated in Figure 2.1. The tubes form a matrix and are individually identifiable by a numbering pattern as shown in Figure 2.2. Note that there are no tubes on one side of Row 76, which forms an open tube lane to the center of the tube bundle. This open lane was intended to provide a means for tube bundle inspection on the initial operating OTSG's.

The maintenance of steam generator tube integrity was recognized early in the design of the OTSG as requiring special consideration. Accordingly, considerable effort was expended in the design, fabrication and setting of operational requirements. All OTSG's utilize full flow condensate polishing with volatile chemical additives to provide high quality feedwater with pH and oxygen control. Solids such as sodium phosphates have never been added to the steam generators. The straight tube design minimizes possible locations for stagnation while the once-through mode of operation eliminates bulk concentrations of impurities. Scale model and initial testing were performed to assure freedom from vibration damage.

Operation of the once-through-steam-generators until July, 1976 has been exceptionally good and has conformed with expectations. During this period two in-service inspections of each of the Oconee 1 steam generators had been performed at the first two refueling outages. (November, 1974 and March, 1975). An in-service insp ction of both Oconee 2 steam generators was also performed at the first refueling outage (April, 1976). These inspections were performed in the manner prescribed in Regulatory Guide 1.83. The results of eddy current testing did not reveal any tubes which had a detectable wall penetration greater than 20%.

Visual examinations of the steam generators through manways and handholds at various levels were selected to permit viewing potential problem areas. Fiber optics were also used to permit viewing locations where access openings were small and to examine the tubes and tube support plates at points which would otherwise be inaccessible. The generators were exceptionally clean and free of deposits. No evidence of tube to tube support plate interaction was seen. Attempts to collect oxide samples were futile due to the minimal amount present. No detrimental effects could be determined.

In July, 1976 a steam generator tube leak occurred on the Unit 3 "B" OTSG. This was the first instance of a tube leak on any operating B&W OTSG and was thought to be the result of a random tubing defect. The leaking tube was identified as tube 77/11 (tube 11 of row 77) and eddy current testing revealed an indication at the 15th support plate. Eddy current testing was performed on the adjacent tubes to assure that they were not damaged and the leaking tube was removed from service by explosively plugging at the top and bottom.

In September, 1976 an inservice inspection was performed on both Oconee 3 OTSG's during the refueling outage. None of the tubes in either steam generator had indications exceeding 30% of wall thickness. In all four tubes in the 3 "B" OTSG indications of wall thinning between 30% and 20% were detected. All other tubes indicated less than 20% wall thinning. Visual examinations confirmed the cleanness of the steam generator.

On October 31, 1977 a second steam generator leak occurred on the Oconee 1 "A" steam generator. A program of investigation and repair similar to that performed on the previous (Oconee 3) leak was conducted. Additionally, a visual inspection of the leaking tube, 77/17, was conducted using fiber optics techniques. This revealed the presence of a circumferential crack at the upper tube sheet.

Immediately following the second tube leak an extensive effort was initiated to determine the cause of the leaks and to implement corrective actions to resolve the problem. As envisioned at that time, the program consisted of six phases:

1. Problem identification - to review the approaches taken by other vendors and ability to identify tube leaks.

2. Potential mechanisms for tube failures - a compilation of all potential mechanisms for investigation.

3. Data Collection and Analysis - review of existing eddy current data, plant history, transients, water chemistry, manufacturing history, etc.

4. Determine causes of tube leaks.

5. Develop fixes.

6. Implement fixes.

The capability to remove a defective tube (see Section 3.1.3) was developed as this was considered necessary to obtain further information on a tube failure mode. Additionally, a tube stabilizer was developed which would hold captive the upper portion of a defective tube.

In December, 1976 steam generator tube leaks developed in the Unit 2 "B" and Unit 1 "B" steam generators. In Unit 2, the leaking tube was identified as tube 77/23 and the failure mechanism was determined from visual observations to be a 270° circumferential crack at the tubesheet. This tube and one other were removed for detailed examination. The specific findings from visual examinations, chemical analysis, and metallurgical examinations are presented in sections 3.1.1 through 3.1.3 of this report. In general, the crack appears to have been initiated at the center of the arc as an OD defect and to have propagated through the wall and then in both directions around the circumference as a nearly through wall crack. The latter stages of crack propagation clearly indicate the presence of a high frequency, low stress vibration fatigue. No evidence has been discovered which would indicate the presence of inter-granular stress-corrosion cracking. Additionally, chemical and isotopic analyses have indicated nothing unusual.

Table 2-1 details the history of steam generator leaks in the three Oconee units and the corrective actions taken with regard to inspections, tube plugging, tube stabilizing and tube removals. Specifically, there have been a total of eleven leaks. Of these, all but one have occurred in the "B" OTSG's. Further, the majority (9) of these have been in tubes on or close to the open tube lane and all have been at the upper tube sheet or the upper two tube support plates. The distribution between units has been 6, 1, and 4, respectively for the three units.

In February, 1977, the review of operating history identified the potential cause of the tube failures as the turbine stop valve testing which was performed on a daily frequency. A description of this phenomenon is provided in section 3.2.1 of this report. Investigations were performed into this phenomenon using installed instrumentation in February and March, 1977. The results of this testing has identified the need for further investigations and instrumentation has been installed in the Oconee 2 "B" OTSG for this endeavor. A description of the proposed testing program is in section 4.0. The first three phases of the six phase program began in November, 1976 are essentially completed. The results of testing which is described in section 3.1 of this report has not yielded information from which a specific cause of tube failures can be identified. Continued testing is being performed in certain areas such as visual examinations, eddy current testing, etc. Certain corrective actions have been taken with regards to turbine stop valve testing (see section 3.2.1) which it is felt will decrease the frequency of tube leaks. Program of instrumentation of the "2B" OTSG has been accomplished and testing will be started in the near future. Further planned actions are described in section 4.0.

TABLE 2

SUMMARY OF MAJOR OTSG TU EXPERIENCE AT OCONEE

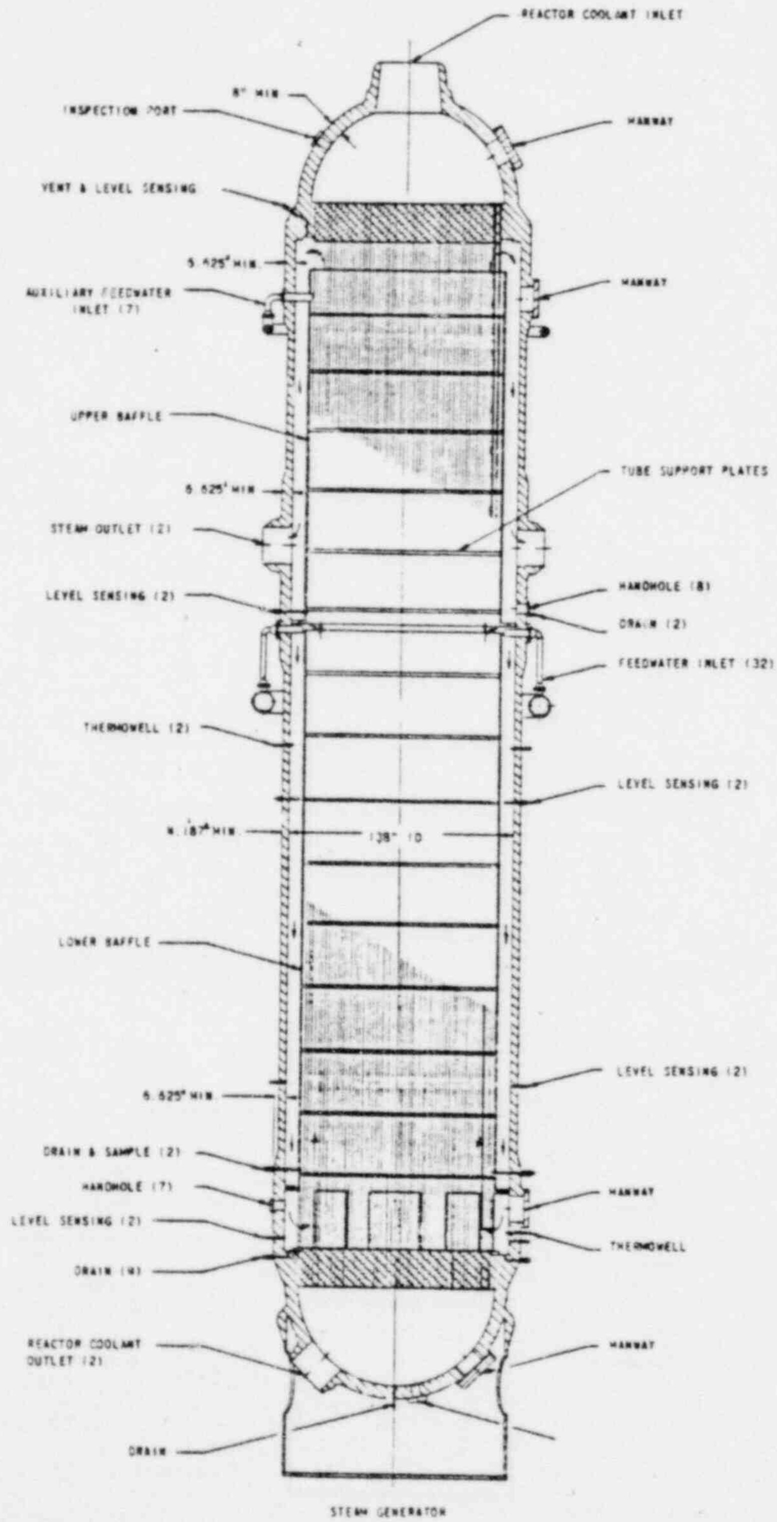
GENERATOR	ROW	TUBE	ELEVATION	DATE	LANE TUBE	LEAKER	CONDITION	ACTION	RO#	# TUBES EXAMINED (excludes leakers)
1-A	77	17	Tubesheet	10/31/76	Yes	Yes	Crack	Plugged	RO-269/76-17	15
1-A	77	18	Tubesheet	10/31/76	Yes	No	Distorted Eddy Current Signal	Plugged		
1-B	114	109	14th Plate	12/8/76	No	Yes	No Visual Inspection	Stabilized	RO-269/76-19	139
1-B	113	115	14th Plate	12/8/76	No	No	Distorted Eddy Current Signal	Plugged		
1-B	113	110	14th Plate	12/8/76	No	No	Similar to 114/109	Stabilized		
1-B	75	18	Tubesheet	12/8/76	Yes	No	300° Crack	Stabilized		
1-B	75	12	Tubesheet	1/15/77	Yes	Yes	350° Crack	Stabilized	RO-269/77-2	140
1-B	81	128	Tubesheet	1/15/77	No	No	Eddy Current Indication	Stabilized		
1-B	32	13	14th Plate	2/28/77	No	Yes	Eddy Current Indication	Stabilized	RO-269/77-8	3%
1-B	33	14	14th Plate	2/28/77	No	No	Eddy Current Indication	Stabilized		
1-B	77	25	14th Plate	2/28/77	Yes	No	Eddy Current Indication	Removed		
1-B	2	7	13th Plate	2/28/77	No	No	Eddy Current Indication	Plugged		
1-B	2	8	13th Plate	2/28/77	No	No	Eddy Current Indication	Plugged		
1-B	101	40	4th Plate	2/28/77	No	No	Eddy Current Indication	Plugged		

TABLE 2.1
SUMMARY OF MAJOR OTSG TUBE F[illegible]RIENCE AT OCONEE (CONT'D)

GENERATOR	ROW	TUBE	ELEVATION	DATE	LANE TUBE	LEAKER	CONDITION	ACTION	RO#	# TUBES EXAMINED (excludes leakers)
1-B	77	25	Tubesheet	3/22/77	Yes	Yes	Weld Crack	Replug-ged	RO-269/77-11	100
1-B	77	3,5,8,	---	3/22/77	Yes	No	Distorted Eddy Current Signal	Plugged		
1-B	77	15	Tubesheet	5/7/77	Yes	Yes	Crack	Plugged	RO-269/77-16	507
1-B	77	18	---	5/7/77	Yes	No	---	Removed		
1-B	17	5	---	5/7/77	No	No	Distorted Eddy Current Signal	Plugged		
2-B	77	23	Tubesheet	12/4/76	Yes	Yes	270° Crack, Hole	Removed	RO-270/76-15	133
2-B	77	[illegible]	15th Plate	12/4/76	Yes	No	Wear Appearance	Removed		
2-B	124	42	12th Plate	12/4/76	No	No	Eddy Current Indication, 40-60%	Plugged		
2-B	118	52	12th Plate	12/4/76	No	No	Similar to 124/42, 15%	Left		
3-B	77	11	15th Plate	7/21/76	Yes	Yes	No Visual Inspection	Plugged	RO-287/76-10	9
3-B	77	19	15th Plate	2/14/77	Yes	Yes	Eddy Current 45° Crack	Stabilized	RO-287/77-2	142
3-B	77	12,13,14,15 16,17,18,20, 21		2/14/77	Yes	No	Eddy Current	Stabilized		
3-B	75	2		2/14/77	Yes	No	Eddy Current	Stabilized		
3-B	78	1	15th Plate	6/10/77	No	Yes	90° Crack & 1/8" longitudinal	Stabilized	RO-287/77-8	133

TABLE 2.1
SUMMARY OF MAJOR OTSG TUBE E .IENCE AT OCONEE (CONT'D)

GENERATOR	ROW	TUBE	ELEVATION	DATE	LANE TUBE	LEAKER	CONDITION	ACTION	RO#	# TUBES EXAMINED (excludes leakers)
3-B	77	2	Tubesheet	7/14/77	Yes	Yes	60^{o}-90^{o} Crack	Stabilized	RO-287/77-10	120
3-B	77	1	---	7/14/77	Yes	No	---	Stabilized		



STEAM GENERATOR

FIGURE 2-1

OTSG TUBE IDENTIFICATION

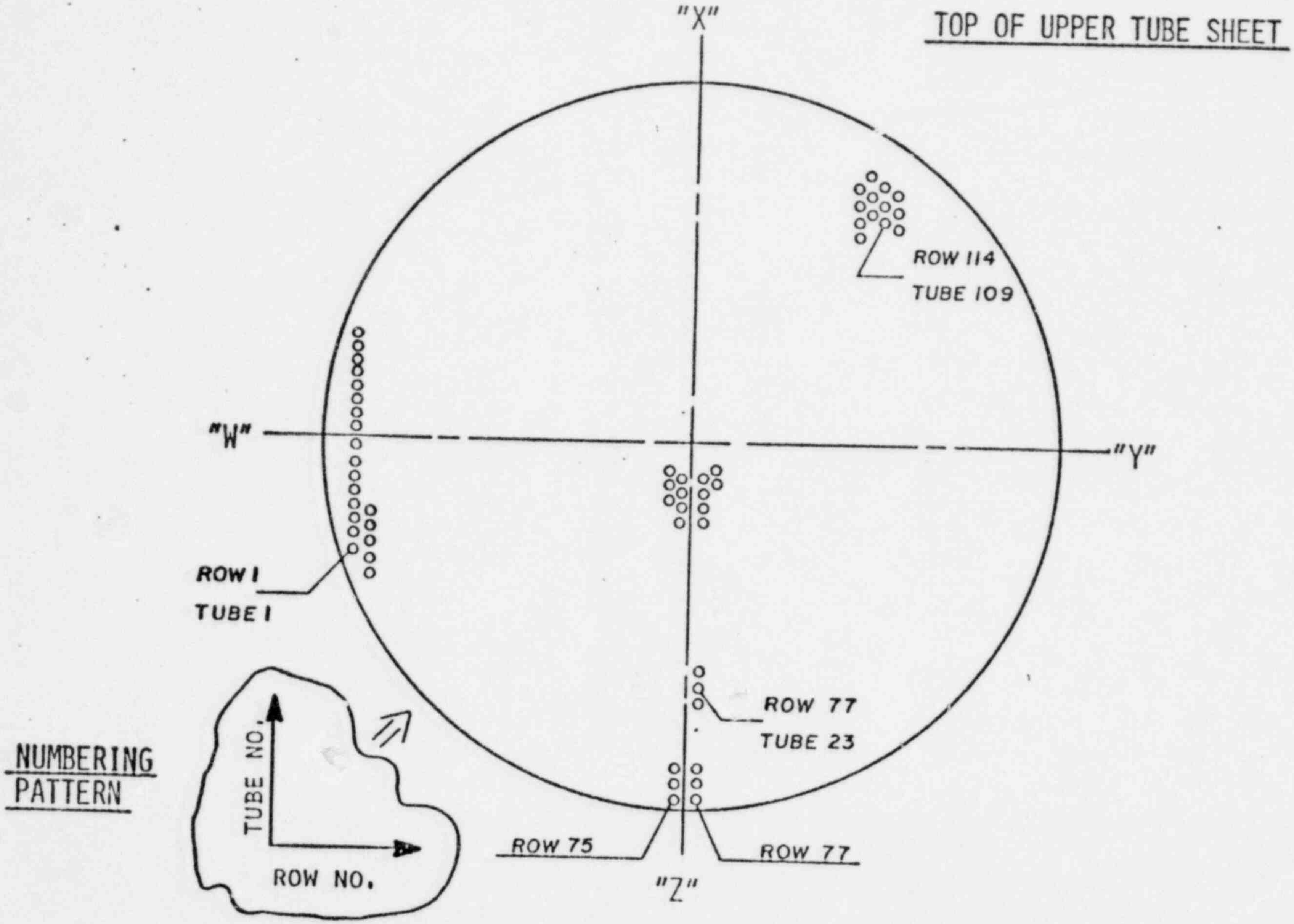


Figure 2-2

3.0 ACTIONS TO DATE

The purpose of this section of the report is to identify those actions which have been performed to date. Although no significant mechanism for the steam generator tube leaks has been confirmed, these efforts have been valuable in limiting the potential failure mechanisms. As a result of these actions, the future investigations described in Section 4.0 have evolved. Section 3.2 describes those specific actions which have been taken to alter the station operating procedures and equipment in an attempt to investigate the possibility of future tube ruptures.

3.1 Evaluations Performed and Results

3.1.1 Visual Examinations

Early in the investigative work to determine the cause of the steam generator tube failures at Oconee, the importance of visual examinations of the steam generators was recognized. This program was initiated with the second tube leak on Oconee 1 in October, 1976 and has been enhanced during further examinations.

It is felt that the visual inspections provide important information in several areas:

1. Verification of the defective tube.

2. Visual evidence of the type and extent of the tube defect for correlation to eddy current testing (ECT) signals and leak rates. The type of defect is also important in formulating an initiation mechanism.

3. Information on the condition of the OTSG with respect to tube surface deposits, support plate and tube sheet corrosion, fretting, tube bowing, etc.

The visual inspections are performed by the use of fiber optics equipment. The equipment consists of a fiberscope of either three or four meters length, a light source, an eyepiece, a 35 mm camera, a TV camera and video monitor, and adapters for connecting the cameras and eyepiece. The three meter fiberscope has a side viewing lens while the four meter fiberscope has interchangeable side viewing or forward viewing lenses. A video tape machine has also been used to record a number of the inspection observations.

The inspection of the tube ID is performed as follows:

The fiberscope is inserted through the upper head inspection port into the upper head waterbox. A man enters the upper head waterbox, locates the tube of interest, inserts the fiberscope, and exits. The inspection is then performed by manipulating and withdrawing the fiberscope from outside the upper head inspection port. In this way, personnel radiation exposure in the high radiation field of the upper head waterbox is minimized.

This technique limits the inspection to approximately the top five feet of the tube when using the three meter fiberscope. This range is extended to approximately eight feet when using the four meter fiberscope which was recently obtained. This covers the range of the critical area where the majority of the tube defects have occurred. However, the resolution of the longer fiberscope when using the side viewing lens is somewhat poorer than the three meter fiberscope on the tube ID because of its longer focal length optics. Therefore, although defects can be located, some details are lost when using this arrangement. It should be emphasized, however, that all major defects within the range of the equipment have been located and characterized by using a combination of the lenses.

Inspection of the tube OD and the secondary side of the OTSG is performed by securing the fiberscope to a ½" ID stainless steel tube with tape, bending the tube and fiberscope to the necessary configuration, and inserting the assembly through the auxiliary feedwater nozzle and down the open tube lane.

When using this technique the tubes on either side of the open lane can be observed from just below the 15th support plate up to the upper tubesheet. Because of difficulties in manipulating this apparatus, the specific area being viewed when at the upper tubesheet is sometimes difficult to ascertain. As experience is gained in the manipulating and as more tubes become identifiable at known locations this difficulty is being overcome. Unit 3 has an internal ring header design for auxiliary feedwater introduction. This design has no entry port on the Z-axis (open inspection lane). Therefore, visual inspection of the secondary in the upper region is not possible.

To date, twelve tubes have been identified as leakers by hydrostatic testing and/or identified as major defects by ECT. Nine of these have been visually observed on the tube ID. Fiber optics equipment was not available at the time of the first leak (July, 1976) and two of the subsequent leaks were in locations which were not accessible with the equipment available.

In general, the defects have all appeared as circumferential cracks extending from 30° to 350° around the tube. The smaller cracks have been clean and regular while the larger cracks have had areas which are more ragged in appearance. This ragged appearance was probably due to impacting of the crack surfaces during propagation. A slight discontinuity in the regular surface has been observed for the majority of the cracks. This discontinuity has taken the form of an "inverted U" shape and may be indicative of the crack initiation point. Six of the nine visually observed tubes have had no indication of any branching, and two have each had one extremely small branch at the discontinuity. Tube 78-1, OTSG 3-B, is an exception and will be discussed in more detail later.

From the OD the tubes have, in general, appeared as described above. Since the only portion of the tube which can be viewed from the OD is the half of each tube facing the open lane on Units 1 and 2, the cracks have not always been observable from the OD.

Generally, the tubes, upper tubesheet, and 15th support plates surfaces in the upper span region have appeared in good condition with slight deposits present. However, shiny areas have been observed on several occasions above or just below the 15th support plate. This may be indicative of a rubbing or fretting type action in this location or may be a visual anomaaly. A tube with this type indication was removed from OTSG 2-B in July, 1977 for analysis.

The following is a brief summary of the visual inspection results during the tube leak outages. A number of other visual inspections have been performed during various outages but their findings have not been significantly different from those listed.

July, 1976, OTSG 3-B: No visual inspection performed.

November, 1976, OTSG 1-A: 90° circumferential crack near the lower face of the upper tubesheet (UTS) in tube 77-17 from ID. No OD inspection.

December, 1976, OTSG 1-A: Performed secondary inspection. Defect in tube 77-17 not observed. Tube surfaces in good condition. Slight deposits. No evidence of fretting.

December, 1976, OTSG 1-B: Visual inspection of tube 114-109 (leaker identified by hydro) unsuccessful because of defect location. Tubes 75-18, 77-23, 77-24, and 77-25 inspected from primary and secondary because of ECT indications. Tube 75-18 revealed a circumferential crack of approximately 300° near the UTS on the ID. No evidence of cracks or holes from OD. Deposits present at UTS on several tubes which had given ECT indications.

December, 1976, OTSG 2-B: ID inspection of tube 77-23 showed a circumferential crack extending approximately 270° at the UTS. Crack sharp with slight discontinuity at midpoint. No branching. The defect appeared to be a hole with wider diameter at the OD than at the ID when viewed from the OD. Tubes 77-25 and 77-27 identified as candidates for removal because of roughened appearance at 15th support plate (SP).

January, 1977, OTSG 1-B: ID inspection of tube 75-12 showed approximately 345° circumferential crack. "Inverted U" at midpoint. Crack observed from OD appeared similar. Open as much as 1/16" in places. Some slight deposits on OD tube surfaces but nothing abnormal. Tubes 75-13, 75-22 ID inspection revealed nothing significant.

February, 1977, OTSG 3-B: ID inspection of tube 77-19 showed approximately 45° crack at the 15th SP. Discontinuity at midpoint Crack itself not opened.

March, 1977, OTSG 1-B: ID inspection of tube 77-22 showed at 45° to 60° circumferential crack at the upper edge of the 15th SP. OD examination showed only a dark stain inside 15th SP. Clear observation inside SP area is difficult, however. This tube was identified by ECT and not hydro. ID inspection of tubes 77-5 and 77-27 showed no significant features. OD inspection of tube 77-29 showed relatively heavy deposit 1 to 2 inches from UTS corresponding to an E/C signal. Deposit had sharp straight edge on one side. OD inspection of tubes 77-3 and 77-5 revealed possible wear/fretting pattern at lower edge of 15th SP due to its shiny appearance.

May, 1977, OTSG 1-B: ID inspection of tube 77-15 showed a 350° circumferential near the UTS. OD inspection appeared similar. The crack appeared open along much of its length. "Inverted U" at midpoint. Also observed previously stabilized tube 75-18. Could view stabilizer through crack at UTS. Appeared crack has opened up and possibly propagated to greater extent. This tube and nail were removed for analysis.

June, 1977, OSTG 3-B: ID inspection of tube 78-1 showed a 75° to 90° circumferential crack at the 15th SP. The crack appeared very tight at one end, open at the other end. At the open end a vertical crack was also observed at 90° in relation to the horizontal segment. The vertical segment was approximately one-fourth the length of the horizontal segment. No "inverted U" type discontinuity was observed.

July, 1977, OTSG 3-B: ID inspection of tube 77-2 showed a 60° to 90° circumferential crack at the UTS. The crack appeared tight and not open at any location. The "inverted U" discontinuity was observed. However, it was at one end of the crack rather than at the midpoint.

All visually inspected leaking tubes have had circumferential cracks of varying length. It is believed that crack length is a function of the operating time following the initiation of the crack. Continued visual examinations are planned for any future tube leak outages and an extensive inspection of the Unit 1 OTSG's is planned for the present refueling outage.

3.1.2 Chemical Analyses of Deposits

The Oconee Units are operated utilizing an all volatile chemical treatment (AVT) for the feedwater to the once through steam generators. This treatment involves only the addition of ammonia for pH control and hydrazine for oxygen control. Condensate polishing by powdered ion exchange resin demineralzers is utilized for maintenance of feedwater purity. Table 3.1.2-1 provides the feedwater specifications during normal operation. No other type of chemical control has been utilized for any of the three units. Therefore, deposits tend to be primarily magnetite rather than the phosphate precipitation products that have been common in recirculation steam generators.

A summary of the feedwater chemistry history of the three units for 1976 is given in Tables 3.1.2-2 and 3.1.2-3. For the most part, chemistry control has been good. The limits on the sodium, iron, dissolved oxygen, copper, and lead values reported in the tables are indicative of the detection limits of the methods of analyses used for routine chemical control.

During each refueling outage, swipe samples have been taken from the tube surfaces in the lower section of each OTSG. The results of the analyses performed on these samples are given in Table 3.1.2-4. The predominant element is iron, with small quantities of chromium, nickel, and other elements from the corrosion of system materials. Small amounts of feedwater impurities, such as silica, were also present.

Because of the cleanness of the tubes and the difficulty in obtaining sufficient sample quantities for analysis, swipe samples from the upper section of the OTSG have not been routinely taken.

During the December, 1976 outage, the upper sections of tubes 77-23 and 77-27 were removed from the Oconee 2-B OTSG. Preliminary analysis of the chemical composition of the surface deposits on these tubes was performed by energy dispersive X-ray analysis (EDAX) while the fracture surfaces and deposits were undergoing metallurgical examination by scanning electron microscopy (SEM). Scrape samples were later removed from the tubes and analyzed by optical emission methods. Table 3.1.2-5 lists the results of these analyses.

The analyses indicate that the elemental composition of the deposits is innocuous; that is, no indication was found that any corrosive agent was present. It should be pointed out, however, that chlorides, flourides, and some of the sulfur compounds are highly soluble and may have been removed by service washing during shutdown, leak location procedures, and wet layup recirculation. Modified wet layup recirculation procedures are being performed to minimize some of these problems for the Unit 1 refueling outage. Water samples will also be taken for analysis.

It should also be mentioned that the tube deposits at the tubesheet were thick enough to produce intimate contact between the tube deposit and the tubesheet hole surface around part of the circumference. SEM analyses of the tube samples removed indicates that there was such contact.

The deposits appear to be deposition (very chrystalline morphology) solution and not a direct transfer of tubesheet corrosion or oxidation products (non-chrystalline morphology). No corrosion of the support plates or the tubesheet has been observed in either visual or SEM observations.

A few localized tube deposits have also been observed by fiber optics in Units 1 and 2. While such deposits are not necessarily harmful themselves, like the crevice deposits, they do provide the prerequisite conditions for under deposit concentration of any harmful chemical species which might enter the OTSG. A new sampling probe has been developed to be used in conjunction with the fiber optics probes to sample these deposits during the August, 1977 Unit 1 refueling outage. This sampling procedure, in combination with the water samples and modified wet layup procedure, should give a better indication of whether any such concentration is happening at the present time.

In summary, the data to date is too preliminary to reach specific final conclusions about tube failure mechamisms. However, there has been no evidence of tube wastage, chemical attack, or intergranular stress corrosion cracking. Chemical analyses of deposit samples have shown nothing unusual. Metallurgical analyses of removed tube samples indicate crack propagation of a local defect by a high cycle fatigue mechanism. The mechanism to initiate such a local defect has not been identified.

TABLE 3.1.2-1

OTSG feedwater specifications

Normal power operation

Total solids	10 ppb max
Cation conductivity	0.5 μ mhos/cm max
Dissolved oxygen as O_2	7 ppb max
Hydrazine as N_2H_4	1-25 ppb
Silica as SiO_2	20 ppb max
Total iron as Fe	10 ppb max
Total copper as Cu	2 ppb max
pH @ 77F	9.3-9.6
Lead as Pb	1 ppb max

TABLE 3.1.2-2

Summary of average feedwater chemistry values - 1976

Parameter	Oconee 1	Oconee 2	Oconee 3
pH @ 77F	9.41	9.36	9.37
Cation conductivity (μ mhos/cm)	0.30	0.27	0.24
Silica as SiO_2 (ppb)	13	13	19
Sodium as Na (ppb)	<10	<10	<10
Iron as Fe (ppb)	<10	<10	<10
Dissolved oxygen as O_2 (ppb)	<7	<7	<7
Copper as Cu (ppb)	<2	<2	<2
Lead as Pb (ppb)	<1	<1	<1

TABLE 3.1.2-3

Percent of feedwater chemistry data within specification

Parameter	Oconee 1	Oconee 2	Oconee 3
pH @ 77F	92	93	83
Cation Conductivity	99	>99	98
Silica	84	87	72
Iron	>99	>99	>99
Dissolved Oxygen	>99	>99	>99
Copper	>99	>99	>99

TABLE 3.1.2-4

Summary of OTSG tube deposit data

Plant	Oconee 1		Oconee 2		Oconee 3
Operating time at sampling, EFPD	300	600	440	717	472
Deposit, gms/ft^2	0.5	1.2	8.4	-	4.7
Element, *% Iron as Fe_2O_3	Major	Major	Major	Major	Major
Silicon as SiO_2	<0.01	0.1	<0.1	0.3	1.3
Aluminum as Al_2O_1	<0.17	0.07	<0.03	0.07	0.2
Titanium as TiO_2	0.2	0.2	0.1	0.06	1.0
Calcium as CaO	<0.2	0.1	<0.2	<0.01	5.0
Magnesium as MgO	<0.05	<0.05	0.05	0.01	1.2
Sodium as NaO	<0.5	0.5	0.7	---	0.5
Nickel as NiO	3.0	7.4	0.06	0.2	5.2
Chromium as Cr_2O_3	2.3	1.7	0.2	0.2	2.0
Maganese as MnO_2	<0.2	0.2	0.1	0.2	0.5

Cobalt, Zinc, Lead, Tin --------------less than or equal to detection limit-------
Zirconium, & Molybdenum

*elements reported as the oxide due to analytical method used.

TABLE 3.1.2-5

Deposit Analyses of Tubes Removed from Oconee 2-B OTSG in December 1976.

X-RAY DIFFRACTION

Fe_3O_4	MAJOR	
Elemental %	Tube 77-23	Tube 77-27
Lead	0.05 - 0.2	0.1 - 0.3
Aluminum	0.9 - 1.0	1.0 - 3.0
Calcium	0.4 - 2.0	0.5 - 4.0
Copper	0.3 - 0.6	0.3 - 0.4
Zinc	0.2 - 1.0	0.3 - 1.0
Titanium	0.8 - 1.0	0.6 - 0.8
Nickel	1.0 - 3.0	3.0 - 5.0
Silicon	0.9 - 8.0	2.0 - 9.0
Magnesium	0.3 - 0.8	0.2 - 1.0
Manganese	1.0 - 3.0	0.9 - 3.0
Chromium	0.3 - 1.0	1.0 - 3.0
Iron	MAJOR	MAJOR
Tin	0.01 - 0.03	.005- .05
Sulfur	<.2 - <.4	<.2 - 0.4
Chloride	< 0.01	< 0.01
Fluoride	< 0.01	0.0075 - 0.017

Results given as the range of a considerable number of samples from various locations on the tubes.

3.1.3 Examination of Removed Tubes

In order to aid in the determination of the mechanism of OTSG tube failure, it was recognized that removal of failed tubes would be necessary. This capability was developed by December, 1976. Several tubes have been removed from both the Oconee 1 and 2 "B" steam generators for metallurgical examination. The objectives of the tube removal program are two-fold -- (1) determine the mechanism by which the cracks are initiated and propagated; and (2), determine the source of eddy current defect type signals. The tubes removed were selected on the basis of maximizing the information obtained while minimizing personnel radiation exposure.

In December, 1976 tubes 23 and 27 on row 77 of OTSG 2B were removed. Tube 77-23 had a 270° circumferential crack while 77-27 showed an eddy current defect type signal at the 15th tube support plate. (TSP)

Tube 77-25 OTSG 1B was removed in March of 1977. This tube had a 100° circumferential crack and fractured during the removal process. Tube 75-18 OTSG 1B was removed in May, 1977. This tube had been stabilized in December, 1976. It was removed along with the stabilizer to study its performance.

The analyses were carried out using standard metallurgical practices relying heavily on scanning electron microscopy (SEM) to study both the fracture surface and the deposit present on the OD of the tubes. Additionally, energy dispersive X-ray analysis (EDAX) was used extensively to determine the chemical make up of surface deposits and foreign material on the fracture surface. The following is a summary of the results of these investigations.

3.1.3.1 Tube 77-23 OTSG 2B

The crack in tube 77-23 propagated through 239° circumferentially. It appeared to have originated at a localized region on the OD and propagated through the thickness and then in both directions as a through wall entity. The fracture surface had been damaged severely during the removal process; therefore, the details of the failure mode were not as clear as had been hoped. Figures 3.1.3-1 through 3.1.3-4 show portions of the fracture surface of tube 77-23.

Detailed examination of the initiation area showed the crack initiated at several different locations on the OD and at one location on the ID with OD initiation predominating. The nature of the fracture surface at the OD and ID initiation sites was somewhat different. At the OD the crack was crystallographic in nature while at the ID the fracture surface was fibrous. It is believed that the ID initiated crack segments linked up or accommodated the OD cracks which propigated at different elevations. No evidence of intergranular cracking was found.

The crack propagated in both directions circumferentially on different levels. There was also a vertical segment linking the two levels. This apparently formed during circumferential propagation. This is implied by mid-span "beach mark" on both the vertical and horizontal crack segments. The propagation proceeded from initial site by a "structure sensitive" fracture mechanism. The general appearance of the fracture surface changed as the crack proceeded, however, the "structure sensitive" mechanism persisted over the entire span. Slip band cracking, which commonly accompanies fatigue, was also present. Fatigue striations were difficult to resolve during the early stages of crack growth;

however, during the latter stages, the striations were present in the form of terraced topology and were more easily resolved. Measurement of fatigue striation spacing showed crack growth rates of 5 x 10^{-10} to 1 x 10^{-5} inches per cycle. If this were superimposed over the entire span, a minimum 100,000 cycles would be predicted. Assuming 50hz as the natural frequency of the tube vibration, then crack growth could have occurred in 1-2 hours. The midspan "beach marks" are significant in that they indicate a possible change in crack loading, or load direction.

A shallow OD surface depression was observed adjacent to the fracture surface co-incident with the initiation site. This depression was approximately 0.37 inches long, 0.02 inches in height, and 0.001 inches in depth. It is not known whether this depression was created during tube removal or in service. If this is not an artifact, it could have contributed to crack initiation. The surface of the tube was generally covered with a deposit layer. Very near the fracture surface the deposit had been removed. Moving towards the tube sheet a deposit is encountered, followed by a pattern of circumferential parallel lines. These appeared to be impressions transferred to the deposit from the tubesheet, and are thought to be due to "gun drill" markings formed during drilling of the tubesheet hole. This would fix the crack at 0.15 inches below the secondary side of the tubesheet.

Energy dispersive analysis showed no harmful substances present in terms of corrosion. It did however show differences in the chemical makeup of the different surface morphologies. These were considered normal.

3.1.3.2 OTSG 2B, TUBE 77-27

Tube 77-27 OSTG 2B was removed to determine the source of eddy current defect type signals and visually observed wear indications at the 15th tube support plate area. No tube damage was found, however, some spalling of deposit layer was present. This spalling could have produced the eddy current defect type signals and visual observation. The deposit composition at this level was somewhat different from the tubesheet consisting basically of Fe, Ca, and Si, but does not represent a corrosive environment.

3.1.3.3 OTSG 1B TUBE 77-25

Tube 77-25 OTSG 1B was removed March, 1977 and fractured during removal.

This tube was removed to check the topology associated with a suspicious upper tube sheet (lower surface) eddy current indication. Fracture occurred at the 15th support plate around and because of an existing prior service crack at that location. A tenacious deposit buildup was found at the upper tube sheet location; linear breaks or spalls were present in that buildup. Under some spalls the tube surface appeared etched. The deposit was removed to facilitate inspection. A generally circumferential depression (slightly serpentine) was found. This feature yielded contrast in radiographic x-ray images. The depression spanned approximately 180° of tube circumference, 0.0020-inch axial measure and 0.001 to 0.002 inch radial measure. (A similar depression on OTSG 2B Tube 77-23 circumscribed 60°). The near tube sheet depression exhibited axially oriented micro-grooves, minute cavities and grain boundary delineation. Micro crack segments were found located within and near one extreme end of the depression. These cracks were also oriented circumferentially, i.e., 5 small segments of total length about 0.020 inch.

The service crack at the 15th support plate level initiated at the OD and propagated through about 110° of tube circumference. A very distinctive crack propagation pattern fanned out from the origin. Microscopically the crack was relatively flat and on one level and it exhibited considerably more relief near the origin than OTSG 2B-Tube 77-23. Additionally, there was a transgranular crystallographic or structure sensitive texture close to the origin; this characterized the predominantly radially directed portion of the crack. The crack became flatter (striated topology with slip band cracking) outside the structure-sensitive region where propagation was essentially circumferential.

Striation spacing measurements were on average about 5×10^{-6} inches and changed relatively little over the span. (No striations were resolved in the structure sensitive region). Thus the propagation pattern and rate of propagation of this crack is similar to that for Tube 77-23 OTSG 2B.

The crack origin was situated at an elevation about 1/8-inch below the top surface of the 15th support plate within a band of metal loss or wear on the tube OD.

The metal loss or wear band measured 1/8-inch in width by .003 to .005-inch depth (radial metal loss). Three bands of metal loss were situated at about 120° intervals around the tube circumference. The degree of metal removal was not the same at all locations. The affected areas appear to correspond to support plate land surface locations. The metal loss surfaces exhibited smoothed topologies with micro-grooves formed like river valleys. Positive-relief "mesa-like" features were also present with surrounding material lost on all sides. Original tube surface markings were evident on top of the mesas.

These topologies suggest erosive forces at work, (e.g. spalled deposits swept through the space between tube and support plate land); alternatively processes of fretting, cavitation, and corrosion can not be ruled out. The mesa features tend to rule against direct metal to metal abrasive contact between tube and support plate.

A small micro-crack segment, not directly related to the major crack, was also found within the metal-loss band at the same circumferential position as the service crack origin but at a slightly different elevation. This segment was also circumferentially oriented.

The metal loss or wear surfaces (both UTS and TSP) appear to determine the position of cracks and may be involved in the actual crack initiations.

3.1.3.4 OTSG 1B TUBE 75-18

Tube 75-18 removed in conjunction with the removal of a stabilizer. A detailed examination of this tube has not been completed. Initial study of the stabilizer removal showed no significant wear.

3.1.3.5 FUTURE STUDIES

Removal of other tubes for study has been planned. During the recent Unit 2 refueling outage, a tube was removed from OTSG 2B. Removal of several tubes during the up-coming Unit 3 refueling is being considered, including one full length tube.

It is felt that metallurgical studies of the three previous tubes has revealed much in terms of crack initiation and propagation mechanisms. Further tube removal and examination should confirm these results and help determine the cause of the leaks.

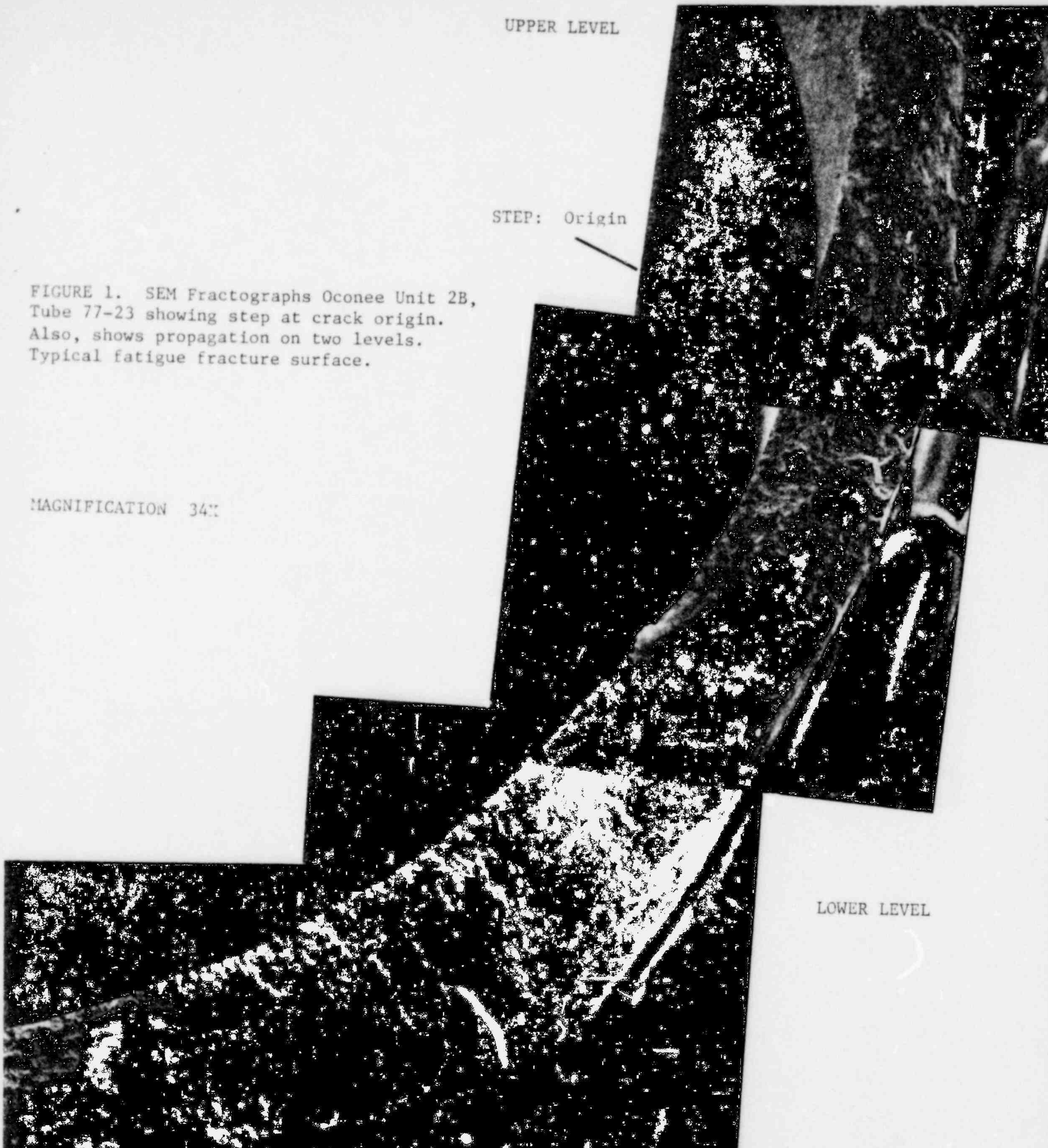


FIGURE 1. SEM Fractographs Oconee Unit 2B, Tube 77-23 showing step at crack origin. Also, shows propagation on two levels. Typical fatigue fracture surface.

MAGNIFICATION 34X

BEACH
MARK

Indicates a change in load or load direction

FIGURE 2. SEM Fractographs of Oconee Unit 2B Tube 77-23 shows LOWER LEVEL propagation. Shows a small portion surface sheared during removal.

MAGNIFICATION 34X

FAILED DURING REMOVAL

WEDGE: Probably formed during tube removal

FIGURE 3. SEM Fractographs of Oconee Unit 2B
Tube 77-23 shows origin plus UPPER LEVEL
propagation. Two crater type artifact possi
bly produced by impacting are arrowed.

MAGNIFICATION 34X

FIGURE 4. SEM Fractographs of Oconee Unit 2B Tube 77-23 shows UPPER LEVEL BEACH MARK. Both UPPER and LOWER BEACH MARKS were symetr[illegible] with respect to the crack origin.

MAGNIFICATION 34X

3.1.4 Computer Evaluation of Eddy Current Test Data

In the latter part of 1976 and in 1977 a number of steam generator tubes leaks occurred in the Oconee steam generators. Eddy current testing techniques were determined to be the best and most efficient method for axially locating these flaws. This method has also proven to be adaptable to steam generator inspections since it is relatively rapid and can be performed remotely, thus minimizing personal radiation exposures.

The tubing failures have occurred at the lower face of the upper tube sheet or at the upper face of one of the two top tube support plates. Conventional eddy current testing yields signals are difficult to interpret at these locations. This is because a tube support plate or a tube sheet edge produces a large eddy current signal. If an abnormal condition exists at the tube support plate or tubesheet the signal will be distorted (a composite signal will exist due to the superposition of the tube anomaly and the characteristic tube support member signal). The composite signal may have virtually any shape dependent upon the flaw size, through-wall depth, and exact positioning relative to the support member edge. In order to overcome this liability of conventional eddy current data analysis, a computer analysis of the data was developed and used to analyze the data from the Oconee steam generators. The basic approach was to use computer techniques to vectorially subtract "normal" support member signals from distorted ones to yield the "flaw" signal (the signal which produced the distortion). Once separated from the support member response, this indication can be evaluated by conventional eddy current test criteria to determine whether or not it is of significance. The approach was successfully demonstrated by Babcock & Wilcox (B & W) in extensive laboratory tests in 1976.

This program has been particularly vigorous in the area of the open lane of the steam generator where the majority of the failures have taken place. When a failure in this area has occurred, both sides of the lane have usually been totally tested. Additional tubes have also been tested at each outage based on previous signals and/or their location with respect to the tube failure. On several occasions, an inspection of an additional 3% of the OTSG tubes was also performed. More than 2000 tubes have been tested during unscheduled tube leak outages and more than 5500 tubes have been tested during inservice inspection. Any signals which appeared suspect have been computer analyzed immediately. Other data (including past data inservice inspection data) is being computer analyzed as time permits. A mini-computer system should be available by September, 1977 to perform these analyses on site.

The technique has been shown to be capable of discerning thruwall circumferential cracks at the tubesheet edge and at support plates. It has located the leaking tubes well and has identified a number of other degraded tubes. Two nonleaking tubes with ECT crack indications have been verified as circumferential cracks by fiber optics. However, its success at predicting failures by locating small beginning cracks at the tubesheet or support plates and being able to identify them is unlikely. The probe is not capable of such localization and the metallurgical analyses indicates that the failure is extremely rapid after the initiation. Its capability in sizing partial tube penetrations at the tubesheet or support plates is also somewhat questionable. This is especially true if the area has been cold worked (such as by rubbing or impacting) since this changes the phase angle and generally causes overestimation of the depth.

The general approach in this area is to try to acquire sufficient reference data to be able to define a signal that is a precurser of a tube defect and/or indication that will elucidate the necessary mechanical and physical preconditions for a tube failure and its initiating mechanisms. Many tubes have been reexamined several times. There appears to be no decernible trend in tube degradation with time. If isolated tubes appear to be slightly degraded, they are monitored at each successive outage. When and if these tube degradations exceed 40% wall thinning they are plugged or stabilized.

The technique has identified "distorted" signals at the tubesheet and the tube support plate locations which can be duplicated in the lab by an extremely small crimping or dinging of the tube. It should be emphasized that these are <u>not defect signals</u> and cannot be interpreted by standard eddy current techniques. The magnitude of these analyzed signals (which in many instances are very close to background interferences) is not directly relatable to the probability of tube failure. A large amount of data over a significant period of time has been obtained during the leak outages. An effort is being made to trend this data with time and attempt to correlate possible failure preconditions. A computer program is being developed to help perform such correlations. A number of tube removals, including the removal of a full length tube, is also being considered to better define the origin of these signals.

During the present refueling outage of Oconee 1 a major program will be conducted on the steam generators. Since the identified failures are concentrated in the area adjacent to the open lane, a greater emphasis will be placed in this area. Approximately 1000 tubes/generator will be examined.

The program will initially include testing of the following tubes:

a) Along the open lane in all tubes rows 75 & 77

b) Adjacent to the open lane in all tubes rows 74 & 78

The data will be analyzed and compared to previous data for possible trends and/or abnormalities in the eddy current signals that can be correlated with potential failure mechanisms or preconditions.

The routine eddy current program proposed in our June 21, 1977 submittal will continue to be carried on during refueling outages and specialized eddy current searches will be done when and if leaking tubes are detected. The pattern used for the leaking tubes will be determined by the position and nature of each individual leaker occurrence.

3.1.5 Review of Manufacturing History

An evaluation of historical data relative to the design and fabrication of the six Oconee steam generators has been conducted. This work involved a review of the manufacturing processes performed, the materials used, the variations/deviations during assembly and all pertinent design related features. The purpose of this effort was to determine if there existed a correlation between any of these items and the tube failures being experienced at the Oconee site.

To complement the above, an investigative study of a similar nature was conducted on B&W generators at other plant sites currently in operation. The objective being to establish if a unique hardware related condition existed at Oconee which could be the source of the tube failures.

In the course of performing this assessment, many pieces of information were considered. Several of the more significant points and resulting conclusions are as follows:

1. All B&W generators currently in operation are essentially of the same basic design. However a specific feature which does vary is the location of the auxilary feedwater header system. This system may be either an internal or external arrangement. As both concepts are present at Oconee, as well as on other generators which have not experienced tube failures, this difference is not considered to be directly related to the cause of the tube failures.

2. A variety of tubing manufacturers have been utilized in the construction of the Oconee generators as well as on other contracts. One vendor will, however, supply all the tubes for a specific unit. Because two different vendors supplied the tubes for Oconee and these same vendors have supplied tubes on units which have not experienced tube failures, it is not considered likely that a vendor related problem exists.

3. Tube rows 75 and 77 have experienced a majority of the failures. It does not appear that any unique tube material characteristic is prevalant among these tubes. The tubes in these rows come from a wide variety of material heats and single tubing supplier shipments. Material test reports for lane tubes as well as failed tubes have been reviewed and there exists no significant difference between the chemical and physical properties of these tubes and others within the tube bundle. All properties are within acceptable standards.

4. Major deviations in fabrication from shop processing and design configurations were closely surveyed. No factor unique to the Oconee generators could be identified to be associated with the tube failures.

On the basis of the investigative study undertaken, it does not appear that the current tube failures being experienced at Oconee are directly linked to a manufacturing concern.

3.1.6 Review of Operating Procedures and History

In order to determine whether or not Oconee steam generator tube leaks were related to operational factors a review of each units operating history was performed. This review was directed in depth at the period of time immediately preceeding all of the tube leaks which have occurred during 1977 (7) and, more generally, at each units total operational history.

With regard to the seven steam generator tube leaks which have occurred during 1977, the period of time from the last turbine stop valve test until indication of a leak was seen on monitor RIA-40 has been reviewed. This period of time was chosen for in-depth evaluation as the result of the postulation of a correlation between turbine stop valve testing and steam generation tube leaks. The date of each tube leak and the associated review period are given below:

		Review Period	
Date of Tube Leak	S/G	From	To
1/15/77	"1B"	1/14/77 @ 2230	1/15/77 @ 1900
2/14/77	"3B"	2/13/77 @ 2156	2/14/77 @ 0610
2/28/77	"1B"	2/25/77 @ 1446	2/28/77 @ 1130
3/22/77	"1B"	3/20/77 @ 0015	3/22/77 @ 1910
5/7/77	"1B"	4/23/77 @ 1442	5/7/77 @ 0530
6/10/77	"3B"	6/9/77 @ 2225	6/10/77 @ 0430
7/14/77	"3B"	6/27/77	7/14/77

For the periods of interest, records of operational events and other-than-normal conditions (as provided by the utility and alarm type printouts) were reviewed to identify any occurrences which could possibly affect reactor coolant, main steam or feedwater pressure, temperature or flow. These parameters were selected based on the consideration that any mechanical degradation of steam generator tubes (the observed mode of failure) would most likely be related to variations in pressure, temperature and flow in the systems identified. In excess of 300 individual recorded events were identified and evaluated, of types such as:

a) Cycling of main steam and feedwater control valves

b) Variations in condensate and feedwater heater and tank levels.

c) Turbine bearing vibrations.

d) Reactor power tilt and imbalance.

e) Condensate booster pump on/off cycles and flows.

f) Integrated control system operational modes.

Those items which would not cause differential conditions between a units steam generators and those items which were not common to the tube leaks under consideration were eliminated from further evaluation. As a result, no items were identified for the periods of interest which could be correlated to the subsequent tube leaks, other than the postulated initiating turbine stop valve tests.

In addition to the detailed evaluation described above, a general review of each units operational history has been performed. Unit trip and transient records were reviewed and items such as startups, shutdowns and trips were identified. The period of time between the most recent unit trip or shutdown and a steam generator tube leak received particular attention. This review has revealed no items which can be directly related to individual tube leaks or to the observed differences in tube leak frequency between units.

Periodic testing other than turbine stop valve testing related to unit operation has also been evaluated. The tests considered were those which could affect reactor coolant, main steam or feedwater pressure, temperature or flow due to the relationship of these parameters to the observed steam generator tube failure mode as previously mentioned. Particular emphasis was given to identifying any testing which might preferentially degrade the "B" OTSG's versus the "A" steam generators. No relationship between testing and steam generator tube leaks was evidenced.

In summary, other than turbine stop valve testing no operational factors have been determined to date which can be related to the observed Oconee OTSG tube leaks.

3.1.7 Review of Previous OTSG Analyses and Tests

To address the question of flow-induced vibration in the OTSG, a large-scale investigation aimed at furthering knowledge in this area was undertaken by the Babcock and Wilcox Company. The program began with laboratory model studies at both the B&W Alliance Research Center (ARC) and Babcock-Atlantique (France) and concluded in 1973 with in-field monitoring of the Oconee 1 steam generators. Results of the laboratory and analytical studies, coupled with successful operation of Oconee 1, convinced Babcock and Wilcox that a typical OTSG tube did not have significant vibration.

The possibility of flow-induced vibration of tube banks subjected to crossflow has always been an area of concern to heat exchanger designers. Before 1970, the standard procedure available to the designer was to ensure that the tube's natural frequency and vortex shedding frequency were not coincident. In most cases, this has been successful in avoiding serious problems. At the 1970 Winter Meeting of the ASME, H. J. Conner of Westinghouse Research Corporation identified a mechanism of flow-induced vibration, which he defined as "fluidelastic".* Application of Conner's theory to a typical OTSG tube indicated that there was sufficient margin between the average fluid velocity present in the OTSG and the fluid velocity at which "fluidelastic" vibration would occur. However, due to uncertainties present in analysis, it was decided to proceed with a program of development testing and the selection of instrumentation for installation at Oconee 1.

An extensive program of laboratory testing was undertaken by ARC and Babcock-Atlantique to more thoroughly understand the flow-induced phenomena as applied to the OTSG geometry. The work included a series of velocity profile measurements at the inlet and outlet areas of the Oconee OTSG utilizing the two-dimensional plastic model at ARC. In addition, a 19-tube model boiler was used to supply a two-phase mixture for investigating the effect of steam quality on the maximum amplitude of a vibrating tube since a low-quality steam-water mixture was anticipated in the Oconee 1 OTSG feedwater inlet region.

Concurrently, Babcock-Atlantique constructed a wind tunnel test section at their LaCournove Laboratories which duplicated the Oconee 1 OTSG outlet region. The results of the ARC velocity profiles were used as a check to ensure nearly identical flow patterns. A second model was constructed by Babcock-Atlantique to investigate the effect of higher Reynolds numbers on the fluid elastic vibration phenomenon. Results of the Babcock-Atlantique studies confirmed that the empirical correlation developed by Conner is geometry-dependent to the extent that the onset of vibration does occur at lower fluid velocities for tube banks than for a single row of tubes.

Together with Babcock-Atlantique and ARC, B&W Nuclear Power Generation Division Engineering utilized the laboratory results to formulate an analytical method for investigating the fluidelastic vibration potential in the OTSG geometry.

To confirm the absence of flow-induced vibration in an operating OTSG, it was decided to proceed with development of in-tube accelerometer instrumentation and to investigate alternate schemes of tube monitoring. Additional instrumentation developed for monitoring several tubes from the secondary side of the OTSG included Kaman KD-1901 noncontacting displacement transducers and a closed-circuit television system. Both of these devices were developed for insertion through the auxiliary feedwater nozzle penetrations.

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*H. J. Conner, "Fluidelastic Vibration of Tube Arrays Excited by Core Flow," Presented at ASME Winter Annual Meeting (1970).

Because of the considerable installation difficulties that would be encountered in installing in-tube accelerometers (primarily from the highly-radioactive environment in the OTSG upper head), the Kaman transducers and the CCTV system, together with the loose parts monitoring system, were selected as being the most practical devised. Considerable attention had been given to demonstrating that the accelerometers installed on the OTSG shell and restraints were capable of detecting tube rattling, through simulation at Babcock-Atlantique and through tube plucking of the Unit 3 OTSG at Oconee.

Two Kaman noncontacting displacement transducer assemblies and one TV camera were installed to monitor the motion of a typical OTSG tube. Data taken during escalation to 75% power provided the following information:

a. Peak-to-peak tube motion in the uppermost tube span was small (less than 10 mils).

b. The natural frequency of the monitored tubes varied between 42 Hz (nominal) for OTSG A and 49 Hz (nominal) for OTSG B.

c. The damping ratio of the measured tubes was between 2 and 4%.

On August 9, 1973, Duke Power Company initiated escalation of Unit 1 to 95% power. During the 24-hour escalation period, the Kaman probes, the CCTV system, and the external accelerometers were monitored at 5% power increments. No significant tube motion was found between the 75 and 95% power levels (tube motion sensed by the Kaman probes was less than 10 mils).

On August 29, 1973, a three-RC pump test was successfully completed, which permitted a steam flow equivalent to 113% power to be achieved in one generator. The data verified that a typical Oconee 1 OTSG tube is free of significant flow-induced vibration for steam flow values up to the approximate 6×10^6 lbm/h achieved during the three-RC pump test. At the same time, no evidence of increasing vibration levels for increasing steam was found.

The tube vibration monitoring program at the Oconee site provided confidence in the Oconee 1-type steam generator. The monitoring program supplied information on damping present under actual operating conditions and on tube natural frequencies that could be correlated against single-tube bench tests and cold OTSG pluck tests*, as well as against theoretical predictions.

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*P. E. Sensmeier, Vibration and Buckling Characteristics of a Sample Tube From the Once-Through Steam Generator, ARC Report 7830, Babcock & Wilcox, February 16, 1968.

3.1.8 Stress and Vibration Analysis

In late 1976 and early 1977 a number of tube leaks and other tube abnormalities were identified in the B&W OTSGs at the Oconee Nuclear Power Station. The majority of the tube leaks occurred in tube rows 75 and 77 (adjacent to the untubed or open tube lane) between the 15th (uppermost) support plate and the upper tube sheet. Since the previous analyses and tests were performed on a typical tube in the bundle, investigations were begun which concentrated on the behavior of tube bordering the open lane.

There are several key differences between the typical bundle tube and a tube on the open lane. Thermal and hydraulic investigations (Section 3.1.9) predict that steam flow velocities down the open lane are higher than of the bundle. In addition, the steam quality is predicted to be lower in the open lane region. Another effect is that one of the seven auxiliary feedwater nozzles is oriented to spray directly down the lane. In order to assess the effect of these differences, analyses and tests of the stress and vibration of lane tubes have been conducted.

A list of possible failure mechanisms which could be caused by thermal or mechanical effects was drawn up and each examined to determine its likelihood of being the root cause. The stress due to heatup, cooldown and normal operation were first examined. With the exception of vibration, it was concluded that these stresses were no higher for lane tubes than for bundle tubes, and in neither case were stresses high enough to predict failure. The proposition that a DNB instability condition existed on a tube such that a rapidly varying thermal cycle fatigued the tube was investigated. Only a very low stress cycle resulted.

A failure mechanism associated with restrained radial growth of the tube was postulated. In the restrained radial growth theory, a hard deposit carried by the lower quality steam in the lane forms on the outside tube wall. As the tube heats up, the radial gap between the tube and tubesheet or support plate is closed, which compressively plastically deforms the tube. On cooldown the gap is reestablished, then refilled with deposit, and the plastic compression cycle occurs again on heatup. After sufficient thermal cycles, a circumferential crack could develop on either the tube ID or OD slightly away from the support region. Tube examinations for this type of "denting" have not supported this theory.

The thermal effects of auxiliary feedwater injection were investigated. It was postulated that when cold (90°F) auxiliary feedwater is injected into the generator, the peripheral tubes are bathed in feedwater around their entire circumference. However, along the lane, the tubes in the region of primary failure (tubes 10 to 30) have their side facing the bundle shielded from auxiliary feedwater flow by the bundle tubes, while the side facing the lane is bathed in the cold flow. This leads to both a radial (through the thickness) thermal gradient and a thermal bending stress deflecting the tube away from the lane. If the flow oscillates back and forth over the tube due to flow instabilities, sufficient cycles might be achieved to fail the tube. As a result of this conjecture, the auxiliary feedwater nozzles facing the lane have been blocked on Oconee 1 and 2 generators (the Oconee 3 generators have a distribution manifold instead of feedwater nozzles).

Due to higher steam density and velocity in the open lane region, some type of flow induced vibration (FIV) is more likely to occur in this region than in the bundle. This has been demonstrated analytically. Although stress levels of sufficient magnitude to propagate a crack have been calculated, the analytical investigations have failed to identify FIV as the crack initiation mechanism.

In order to provide greater understanding of FIV of the lane tubes, several Oconee 2B steam generator tubes have been instrumented with accelerometers and will be monitored during power operation of the Oconee 2 plant. These results will be used to assess the effect of FIV on the lane tubes.

3.1.9 Investigation of Open Lane Flow Characteristics

Since the majority of tube failures on the Oconee generators have occurred on the tubes bordering the open tube lane, investigations were conducted to determine the differences in steam flow around a typical bundle tube and a tube on the open lane. The conclusion from results to date is the flow characteristics of the open lane region give a worse case environment for these OTSG tubes than the bundle region.

Two studies were condutted to evaluate the secondary flow characteristics of both the open tube lane and the bundle. The objective of the first study was to determine the flow and quality conditions in the Oconee Steam Generators. The flow and quality conditions were estimated for the Oconee 1 geometry at 45, 65, and 95% loads and for the Oconee 3A geometry at 100% load.

The objective of the second study was to estimate the radial and circumferential velocities in the secondary exit region of the Oconee 1 steam generators. Velocities were determined using the 95%-load mass flux distribution determined in the first study, and these results were extrapolated to 100% steam flow conditions. Radial and circumferential velocities were calculated in the open tube lane, the 60° tube pattern arrangement (60° TPA), and the 30° tube pattern arrangement (30° TPA). The three calculation regions (i.e. the open tube lane, the 60° TPA, and the 30° TPA) are shown with respect to the steam generator W and Z axes.

In order to confirm the pressures and flows used in the two studies, measurements of steam flow, pressure, temperature, feedwater flow, etc. will be determined on the Oconee 2B steam generator. This data will be taken in conjunction with the vibration measurements described in Section 3.1.8.

The radial velocities were found to vary approximately as a linear function of radius with the highest velocity at the exit. The open lane radial velocity was calculated to be 1.87 times the 30° TPA radial velocity and 2.29 times the 60° TPA radial velocity. The estimated circumferential velocity is low (less than 1 fps). The best estimate of the open tube lane exit quality is 92% at 95% load. Steam quality in the mid-bundle and periphery regions of the generators is estimated to be 108%.

Experimental studies to confirm parameters used in the analytical study will be conducted on the Oconee 2 OTSGs. The internal OTSG pressure will be measured by two dynamic (fluctuating) pressure transducers mounted in a special probe inserted through an Oconee 2B OTSG auxiliary feedwater nozzle. Two differential pressure transducers and one absolute pressure transducer will be mounted in each of the Oconee 2 OTSGs. These will be used to determine total steam flow.

3.1.10 Analysis of OTSG Upper Head Flow Characteristics

A 1/8-scale two-dimensional model of the OTSG upper head was fabricated and tested to obtain information on the expected primary side velocity distribution inside the upper head. The model was tested with a 180 degree turn at the inlet to simulate the true primary piping arrangement.

As expected, the test results showed a relatively high velocity jet near the center of the tubesheet but displaced from the center away from the upflow run of piping. Eddies were evident on either side of this main jet. The maximum vertical velocity at a point equivalent to 1'-4" above the upper surface of the top tubesheet was 63% of the average velocity in the steam generator inlet piping.

The maximum velocity at a point equivalent to 2 1/2" above the upper surface of the top tubesheet was 32% of the average inlet velocity directed downward and about 45 degrees from the vertical.

This information has been used for various purposes, including setting criteria for the design of instrumentation installed in the head of the OTSG and, in conjunction with three-dimensional model tests, predicting the primary side flow distribution among the tubes in the steam generator.

3.2 CORRECTIVE ACTIONS

3.2.1 Revised Turbine Stop Valve Testing Procedure

A review was performed to identify any possible operation which would result in a steam generator pressure or flow transient. A transient of this nature could be responsible for a vibratory forcing function in the steam generator which could be the cause of the tubing leaks. The review indicated that turbine stop valve testing was one such operation which could create such a transient. This test had been performed monthly on each Oconee unit from their initial startup until July, 1975. At this time, due to a turbine vendors recommendation, the testing frequency was increased to daily on each unit for the stop valves and weekly for the control valves. In March, 1977 when it became apparent that turbine stop valve testing was a possible cause of tubing leaks the test frequency was reduced to monthly in accordance with the technical specification requirements. Since initial startup over 750 turbine stop valve tests have been performed on each unit.

The turbine stop valve testing is considered a strong potential as being the aggravating forcing function which causes the steam generator leaks. Indeed it explains why the three Oconee units have experienced leaks at approximately the same time even though they have accumulated significantly different operating periods. A review of other B&W customers has revealed differences in steam piping configurations or that they have performed significantly less turbine stop valve testing.

In order to investigate the potential of turbine stop valve testing, two separate tests were performed during February and March 1977 to identify pressure/flow transients during stop valve testing. A description of that procedure is provided in Appendix A. Analysis of test data (see Appendices B and C) indicated that when stop valves are closed and re-opened, a significant steam pressure reduction was being experienced. This pressure reduction results in a rapid expulsion of steam from the steam outlet area of the steam generator. This transient appeared to be greater when #3 stop valve was cycled (see figure 3.2.1-1 for valve arrangement). The fact that #4 control valve is normally only 5 percent open appears to magnify the pressure unbalance in the balance line connecting the main steam stop valves.

Since the main steam stop valve testing appears to be a contributing factor to the steam generator tube leak problem, the following corrective actions have been initiated:

1. The turbine stop valve test circuitry has been modified to allow simultaneous testing of two valves. This modification will reduce the steam pressure perturbation by simultaneous testing of valves associated with each steam generator. This modification has been made on all Oconee units.

2. The turbine control valve circuitry will be modified such that the unit operates with full arc steam admission. (All 4 control valves open.) This modification should minimize balance line pressure unbalance. Equipment necessary to perform this modification requires a six-month lead time and will be installed when available.

3. The stop valve disc dump limit switch will be reset to allow full valve travel prior to initiating disc dump. Disc dump is a rapid closure of the valves during the last 3/4" travel. Much of the pressure shock is being experienced during this phase of the valve test. This modification has been completed on Unit 3 at this time. This change will be incorporated on Unit 1 during the upcoming refueling outage and on Unit 2 following the vibration study.

4. Orifices will be installed in the stop valve test mechanism to extend the time required for valve closure and re-opening. This modification should further reduce the magnitude of the pressure transients being experienced. This modification will be installed on Unit 1 and Unit 3 following receipt of the necessary equipment. Unit 2 will remain as is until the upcoming test program has been completed.

5. The following temporary action has been taken and will be in effect until all stop valve test modifications have been completed:

a. Power is being reduced to 65 percent to allow closure of #3 control valve prior to performing the test.

b. Test frequency has been temporarily reduced to a monthly basis until all modifications have been completed.

It is anticipated that the testing program described in section 4.0 will provide further information concerning the role of turbine stop valve testing in the steam generator tube leak problem.

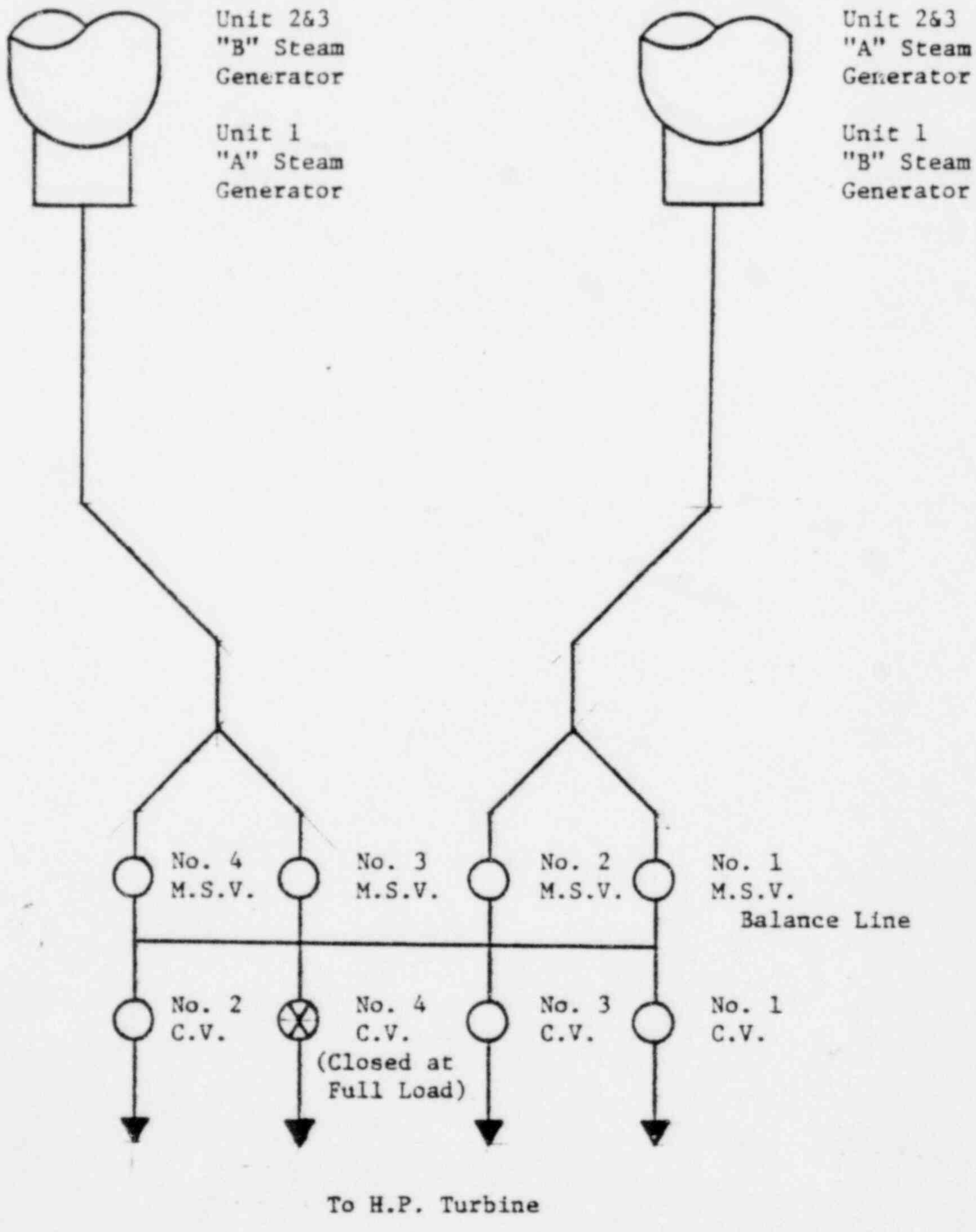

Unit 2&3
"B" Steam
Generator
Unit 1
"A" Steam
Generator
Unit 2&3
"A" Steam
Generator
Unit 1
"B" Steam
Generator
No. 4
M.S.V.
No. 3
M.S.V.
No. 2
M.S.V.
No. 1
M.S.V.
Balance Line
No. 2
C.V.
No. 4
C.V.
(Closed at
Full Load)
No. 3
C.V.
No. 1
C.V.
To H.P. Turbine

FIGURE 3.2.1-1

3.2.2 Tube Stabilizer Development and Utilization

The tube stabilizer is essentially a 1/2 inch diameter rod constructed from individual segments to obtain an overall length of 109 inches. A closure cap is placed at one end of the rod while a rounded nose segment is utilized at the other. The stabilizer is inserted in a generator tube from the primary side at the upper tube sheet elevation. During installation, rod segments are screwed together and then locked to form a rigid connection. The last segment, the cap, is welded to the tube to complete the installation process.

The stabilizer design concept is intended to serve two primary functions. These are:

1. To prevent adverse consequential events as a result of plant operation with generator tubes in the plugged but cracked condition. And,
2. To preclude forced plant shutdowns and repairs due to the failure and resulting leakage of a generator tube.

With respect to item (1), it is reasoned that a cracked but stabilized tube will respond in such a manner so as to reduce the chance that a 2nd fracture will form causing a "loose piece" to exist. In the event that a second fracture is induced, the tube stabilizer will then act as a device to capture "loose pieces".

By inserting stabilizers in tubes with significant eddy current indications or othersjudged to be impending leakers, the possibility of a tube failure and resulting plant shutdown can be circumvented or greatly decreased. In this manner, the functional objective of item (2) is achieved. This aspect of the stabilizer concept is significant in situations where plant availability is an important factor.

In parallel with the development of the stabilizer design concept, an extensive structural qualification effort for the associated hardware has been and is being undertaken. This work involves analytical considerations, laboratory tests, and the removal and inspection of actual stabilizer/tube specimens. To further expand our level of understanding with regard to the actual influence of the stabilizer and its structural integrity, two stabilizers have been instrumented to monitor their in-service response. Results from this test program are currently anticipated to be available by October, 1977.

To date, a total of 29 tubes have been stabilized in 3 out of 6 generators at the Oconee Station. With one exception, in which 10 stabilizers were installed in the Oconee 3-B Generator, tube stabilization has been performed on a very selected and limited basis. At this time, a total of seven stabilizers are present in tubes with known cracks. The current position within B&W and Duke Power is that unless the tube failure problem is clearly isolated to a relatively small and specific number of tubes, the current tube stabilizer design concept will not be adopted as a permanent "fix".

3.2.3 Auxiliary Feedwater Nozzle Blocking

During the early review of the Oconee steam generator tube leaks it was determined that differences existed in the auxiliary feedwater systems of the various B&W plants. It was considered that this could be a contributing cause of the steam generator tube leaks due to the thermal effects of cold auxiliary feedwater which may cause high temperature gradients leading to high stresses in the tubes.

The auxiliary feedwater system consists of a steam driven emergency feedwater pump, associated valves, and piping to supply feedwater to OTSG in specific situations. The pump is supplied from the condenser hotwell and the upper surge tank. This water is normally approximately 90^{o} F. One pump supplies both A and B steam generator auxiliary feedwater headers at 1080 gpm, 1120 psig. On Units 1 and 2 the auxiliary feedwater pump supplies an external header which feeds the OTSG through 7 nozzles. These nozzles inject water into the OTSG between the 15th tube support plate and the upper tube sheet (UTS). One of the nozzles is situated so that auxiliary feedwater flow is directly down the open lane of the OTSG. The auxiliary feedwater header is internal in Unit 3 and does not present this problem.

The auxiliary feedwater system is not normally used to supply feedwater to the OTSG. Primarily it would be used in the case of a loss of normal feedwater flow. It would also be used to supplement normal feedwater flow in case of a loss of all reactor coolant pumps. These cases represent infrequent occurrences, hence, this system is rarely used.

It was postulated that the auxiliary feedwater system operation could have presented a problem in the lane area. During operation of the auxiliary feedwater system a cold stream of water (90^{o} F) is injected down the open lane. The lane tubes may be shielded on the bundle side of the lane so that only the lane side is wetted and consequently cooled. This would cause a large temperature gradient across the tube diameter and the tubes would bow towards the bundle. This would in turn cause a high axial tensile stress on the lane side possibly leading to initiation of a circumferential crack. Propagation of this crack could be by high cycle fatigue via flow induced vibrations. The damaging phenomena postulated would actually be cycling thermal stresses. As the cold feedwater is injected into the lane, at some point radially inward (tubes 10 through 30), it encounters an outflowing steam. Flow oscillations could cause this region to be alternately wet and dried by incoming feedwater and outgoing steam respectively. This could lead to the high cycling stresses which could easily initiate a circumferential crack, which would then be propagated in a high cycle fatigue as mentioned above. It was felt that this cycling effect represents the major concern rather than the actual stress level induced. The other nozzles would not induce a cycling stress since the incoming feedwater is diffused before it encounters outflowing steam.

Based on the information available at the time these studies were made, blocking the auxiliary feedwater nozzle at the lane offered a reasonable and simple solution to the postulated problem. Safety evaluations performed indicated this would have a minimal effect on the operation of the auxiliary feedwater system. Therefore a modification procedure was initiated for Units 1 and 2. Modification of Unit 1 was completed in March, 1977 and on Unit 2 in July, 1977.

4.0 FUTURE ACTIONS

The Babcock and Wilcox Company (B&W) and Duke Power Company are conducting a comprehensive program designed to provide understanding of the steam generator tube leak phenomena and to develop measures to minimize leaking tubes at the Oconee Nuclear Station. The program comprises a number of analytical and experimental studies aimed at determining the precise cause of the tube leaks. These are being conducted in parallel to developmental efforts aimed at correcting the tube leak situation and ultimately improving plant availability. The program is flexible and will be constantly upgraded as new information becomes available and a better understanding of the tube leak situation is attained.

The activities in the overall OTSG tube leak recovery program fall into four major categories. These include Site Activities, Analysis and Laboratory Testing, Field Instrumentation Programs and Design Modification Development. These are listed below with the significant activities that are on-going or under consideration in each category. A summary schedule for each major event is attached.

Site Activities

1. Detailed inspection plans have been developed for Oconee Unit 1 during its current outage and Oconee Unit 3 which has an upcoming, scheduled outage. The inspections will consist of eddy-current examinations and primary and secondary-side visual inspections. Those inspections are aimed at determining the general condition of the generator from a cleanness standpoint and any possible indication of anomalous tube behavior.

2. B&W has developed tooling for removing tube samples for laboratory examinations and has previously removed five such samples at Oconee. This tooling is being upgraded for removing samples at a greater depth (i.e., longer tube samples) in the generator than have been removed in the past. Eddy-current histories are currently being studied to identify candidate samples for possible removal during the upcoming Oconee Unit 1 and Oconee Unit 3 outages. The number of samples to be removed and examined will result from an evaluation of risk, radiation exposure and technical requirements for the need of additional samples.

3. Laboratory simulations of eddy-current signals have previously revealed "ding" like defects at the lower surface of the upper tubesheet, for selected lane tubes. A profilometer is being developed to supplement the eddy-current information with a complete characterization of the internal diameter of the tubes. This should be available for use in the Unit 1 and Unit 3 outages.

4. The nuclear industry through EPRI is considering an extensive program for improving Nondestructive Examination Techniques for steam generator tubes. Among other things, this program considers the use of radial probes, such as the "pancake" probe, for better characterizing the exact nature of flaws in generator tubes. B&W is anticipating that they will actively be involved in these developmental efforts.

Analysis and Laboratory Testing

1. B&W will be analyzing cyclic stress data from the Oconee field instrumentation program and comparing this data with material properties such as high-cycle fatigue strength. This effort will be aimed at determining if gross vibrational stress levels during a specific service condition could possibly exceed the material fatigue strength. It is doubtful that this will be the case; however, these stress levels in the presence of some form of surface degradation may be the source of flaw initiation. A high-cycle fatigue program is underway for determining the required fatigue data for Inconel 600 tubing.

2. Tube failures have occured in four of the fourteen operating B&W OTSG's and all have occured at the Oconee Nuclear Station. Nine out of the eleven failures have occurred in the vicinity of the untubed inspection lane. In some cases, other OTSG's have operated as much as 100 plus effective full power days (EFPD) longer than those units at Oconee without experiencing failures. This suggests a condition unique to the operational characteristics of the Oconee units. B&W and Duke Power Company have conducted extensive investigations to determine any conditions unique to Oconee and have identified the frequent testing of turbine stop valves at full power as such a condition. Flow-induced vibration analyses and the Oconee instrumentation program will be utilized to assess the effects of turbine stop valve testing on tube behavior.

3. The impingement of relatively cold auxiliary feedwater down the open tube lane has been identified as another transient unique to Oconee. This feedwater potentially induces a thermal and vibrational shock to those tubes in the vicinity of the untubed lane. Duke Power has taken corrective action by blocking the subject feedwater nozzle. Analyses and tests to determine the possible deleterious effects of such a transient on the structural integrity of the lane tubes.

4. Thermal-hydraulic analyses to better characterize the flow conditions in the steam generators, particularly in the area of the lane tube failures, are also being conducted. A comprehensive laboratory flow model for confirming the analyses and assessing the effects of possible geometry changes on the important flow characteristics is being considered.

5. Tube samples to characterize the damage observed and to identify the flaw initiation mechanism (s) are and will be analyzed. Currently initiated laboratory tests are aimed at simulating the surface conditions observed on the previously removed tube samples in the areas of flaw initiation. These tests will be aimed at identifying the source of surface degradation (wear, fretting, etc.) and its effect on material properties, such as fatique strength.

While conclusive evidence of corrosive attack has not been observed on the tube samples removed to date, accelerated corrosion tests are being conducted to determine if there is similarity in the metallography of these test articles with the samples removed.

Field Instrumentation Programs

1. The instrumentation of an operating steam generator offers the most potential for understanding the tube vibrational behavior for both normal and transient operation. A vibration measurement program at Oconee Unit 2, in Steam Generator B is currently being conducted. Data will be available in the near future which will be analyzed to determine if excessive vibration occurs in those tubes along the open lane during normal operating and transient conditons, including turbine stop valve testing.

2. B&W is discussing with General Utilities Service Company on the possibility of supplementing the instrumentation program at Oconee 2 with a somewhat more extensive program at Three Mile Island Unit 2 (TMI-2). TMI-2 is currently undergoing Hot Functional Testing (HFT) and avails the opportunity for installing instrumentation in an unirradiated environment when HFT is complete. The instrumentation program will be aimed at measuring vibrational amplitudes in selected lane tubes, bundle tubes, and peripheral tubes for normal operating and transient conditions.

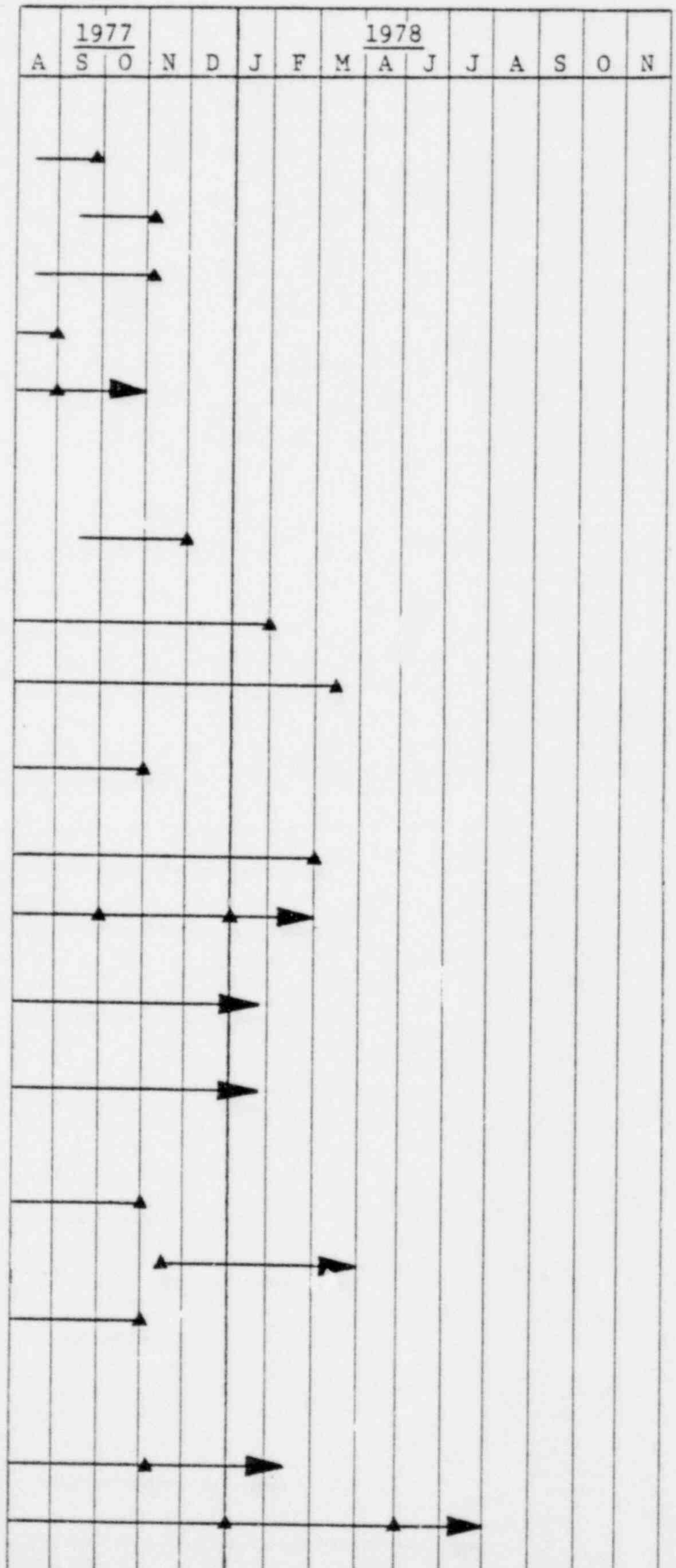
3. B&W is also investigating the feasibility of measuring steam flow in the open tube lane and tube bundle in an operating unit. This flow data could be correlated with tube response in an effort to identify the predominant flow excitation mechanisms which might exist. The results of the program at Oconee must be analyzed and interpreted to better define the scope of future instrumentation in an operating unit.

Design Modification Development

B&W is investigating several potential design modifications which are aimed at reducing the vibrational amplitudes of the tubes or reducing the steam flow velocities in the open tube lane. These design modifications will be evaluated in parallel to the above investigative efforts and may include the development of an internal stiffener (possibly an internal sleeve) which can be inserted from the upper head region. The stiffener will be designed to reduce the amplitude of vibration of tubes, particularly in the regions of steam cross flow.

A method of blocking steam flow from the open tube lane region is being considered. Design concepts for "lane flow blockers" are presently underway and could be evaluated using the previously described laboratory flow-test model.

OTSG TUBE LEAK
EVALUATION/CORRECTION PROGRAM



A. Site Activities

1. Oconee Unit 1 Inspection
2. Oconee Unit 3 Inspection
3. Tube Sample Removals
4. Profilometer Development
5. Improved Eddy-Current Examinations

B. Analysis and Laboratory Testing

1. Analysis of Oconee 2 Instrumentation Results
2. High Cycle Fatigue Testing
3. Auxiliary Feedwater Nozzle Tests
4. Turbine Stop Valve Testing at Oconee 2
5. Accelerated Corrosion Tests
6. Design of Laboratory Flow Model
7. Structural and Vibration Analysis
8. Thermal/Hydraulic Analysis

C. Field Instrumentation Programs

1. Completion of Oconee 2 Testing
2. Possible TMI-2 Testing
3. Multipurpose Flow Probe Development.

D. Design Modification Development

1. Tube Stiffener Program
2. Lane Flow Blocker Program

▲ - Program Decision Points

APPENDIX

A

OCONEE NUCLEAR STATION

TURBINE STOP VALVE AND

CONTROL VALVE INVESTIGATIVE

TEST PROCEDURE

OCONEE NUCLEAR STATION

STOP VALVE AND CONTROL VALVE

STEAM LINE CONDITION TEST

1.0 Purpose

To investigate pressure disturbances in the steam lines from the steam generator to the turbine that occur during stop valve and control valve testing.

2.0 References

2.1 P.O. 122-A-1 - Main Steam System

2.2 P.O. 122-B-2 - HP and LP Turbine Exhaust

2.3 0 422-N11 - Instrument Detail of Main Steam Lines

2.4 TP 1B 0270 32 - Stop Valve and Control Valve Test Procedure

3.0 Time Required

Approximately two (2) hours will be required for data acquisition for each test conducted. At this time, there is no indication of the number of tests that will be required to satisfy the question. No time is estimated for equipment set up for preliminary testing.

4.0 Prerequisite Tests

None Required.

5.0 Test Equipment

5.1 Three Brush high speed trace recorders with four event pens and six analog pens each.

5.2 Two thermocouple amplifiers to be used on main steam at stop valve temperature measurement.

5.3 Existing pressure and temperature transmitters to be input to recorders at the integrated control system panels.

5.3.1 PT 24 P S.G.O. 1A - A Line

5.3.2 PT 25 P S.G.O. 1A - B Line

5.3.3 PT 26 P S.G.O. 1B - A Line

5.3.4. PT 27 P S.G.O. 1B - B Line

5.3.5 RD 9 S.G.O. 1A - A Line

5.3.6 RD 10 S.G.O. 1A - B Line

5.3.7 RD 11 S.G.O. 1B - A Line

5.3.8 RD 12 S.G.O. 1B - B Line

5.3.9	PT 30 A	Main Steam Line A
5.3.10	PT 31 A	Main Steam Line B
5.3.11		Stop Valve 1 - Open
5.3.12		Stop Valve 1 - Closed
5.3.13		Stop Valve 2 - Open
5.3.14		Stop Valve 2 - Closed
5.3.15		Stop Valve 3 - Open
5.3.16		Stop Valve 3 - Closed
5.3.17		Stop Valve 4 - Open
5.3.18		Stop Valve 4 - Closed
5.3.19		Control Valve 1 - Position
5.3.20		Control Valve 2 - Position
5.3.21		Control Valve 3 - Position
5.3.22		Control Valve 4 - Position
5.3.23	SS 11ALT2	Steam Generator A Liquid Level
5.3.24	SS 11BLT2	Steam Generator B Liquid Level
5.3.25	TX	Steam Line A Temp.
5.3.26	TX	Steam Line B Temp.

6.0 Limitations and Precaustions

6.1 Unit power level be maintained at normal 96% for the stop valve and control valve testing.

6.2 The Brush recorders must be synchronized for each valve test.

7.0 Required Unit Status

The unit should be at 96% full power as is prescribed as maximum in the stop valve test procedure.

8.0 Prerequisite System Conditions

The cycle should be set up in the normal operating mode.

9.0 Test Method

This test consists of measuring the variations in the steam line pressures and temperatures as a direct function of the closing and opening cycle of each stop valve and control valve. All data gathered during each test will be recorded on the Brush recorder strip chart and each will be marked accordingly.

Identifying the pressure peak in relation to the valve position will allow the velocity in the steam generator to be calculated.

10.0 Data Required

10.1 Strip Chart Recorded Data - (Location of transmitters detailed in Section 5.0)

10.1.1 A Steam Generator FW Pressure Line A

10.1.2 A Steam Generator FW Pressure Line B

10.1.3 B Steam Generator FW Pressure Line A

10.1.4 B Steam Generator FW Pressure Line B

10.1.5 A Steam Generator FW Temperature Line A

10.1.6 A Steam Generator FW Temperature Line B

10.1.7 B Steam Generator FW Temperature Line A

10.1.8 B Steam Generator FW Temperature Line B

10.1.9 Main Steam Line A Pressure

10.1.10 Main Steam Line B Pressure

10.1.11 Stop Valve 1 - Digitial Signal Open

10.1.12 Stop Valve 1 - Digital Signal Closed

10.1.13 Stop Valve 2 - Digital Signal Open

10.1.14 Stop Valve 2 - Digital Signal Closed

10.1.15 Stop Valve 3 - Digital Signal Open

10.1.16 Stop Valve 3 - Digital Signal Closed

10.1.17 Stop Valve 4 - Digital Signal Open

10.1.18 Stop Valve 4 - Digital Signal Closed

10.1.19 Control Valve 1 - Analog Position Signal

10.1.20 Control Valve 2 - Analog Position Signal

10.1.21 Control Valve 3 - Analog Position Signal

10.1.22 Control Valve 4 - Analog Position Signal

10.1.23 Steam Generator A Liquid Level

10.1.24 Steam Generator B Liquid Level

10.1.25 Steam Line A Temperature

10.1.26 Steam Line B Temperature

11.0 Acceptance Criteria

None, as this is an interpretive test based on actual data during turbine stop valve and control valve testing.

12.0 Procedure

12.1 Pre-test equipment installation and check out.

12.1.1 Install leads from the above listed inputs into the Brush recorders.

12.1.2 All three recorders must be synchronized in order to properly identify timing of the pressure peaks. This will necessitate inputting the signal from each valve to be tested to a strip on each recorder for bench marking the test.

12.2 Conducting of Test

12.2.1 Coordinating with the operating personnel on the start of each valve test is most important.

12.2.2 After each test all strips should be marked and properly identified for later data analyses.

12.3 Test Conclusion

After all data has been taken for each stop valve and control valve test, analysis should be made of resolution of pressure peaks. If not satifactory, additional instrumentation must be obtained in order to improve resolution.

13.0 Enclosures

None

APPENDIX B

SUMMARY OF TURBINE

STOP VALVE TEST PERFORMED

FEBRUARY 25, 1977

OCONEE NUCLEAR STATION

STOP VALVE TEST - FEBRUARY 25, 1977

Unit 1

1.0 Purpose

To investigate possible pressure disturbances in the steam lines that occur during stop valve and control valve testing. Instrumentation was checked both at the turbine and the steam generator outlet in order to correlate the disturbances.

2.0 References

2.1 P.O. 122 A-1 - Main Steam System

2.2 P.O. 122 B-2 - HP and LP Exhaust

2.3 0 422 N11 - Instrument Detail of Main Steam Lines

2.4 TP 1B 0270 32 - Stop Valve and Control Valve Test Procedures

3.0 Description

Four brush strip chart recorders were utilized to record the data on the valve positions, steam pressures, and temperatures and steam generator levels. The exact data utilized is included in the appendix, which is the test procedure used for the tests that were conducted on February 25, 1977. The charts were run at 25 MM/sec to maximize individual surges, while minimizing the "stretch out" factor for the complete cycle of a valve stroke.

Data was compiled for the four stop valve tests, four control valve tests and the six intercept valve tests to make a complete set.

4.0 Evaluation of the Results

4.1 Stop Valve Tests -

From the start of the stop valve testing until completion of the stroke of the fourth valve, approximately 90 seconds of test time was required. The unit was stable at 96% full power and the unit output was only minimally affected.

Refer to Figure No. 1 for valve configurations. While stroking stop valves 1 and 2, pressure upsets were noted in both steam lines with a magnitude of 10 PSIG. "B" OTSG showed an increase while "A" OTSG had a decrease of the same proportion. See Figures 2 and 3.

4.1 Stop Valve Tests (cont'd)

On testing valves 3 and 4, similar pressure changes occurred, but in different directions, due to the fact that the "A" steam line feeds these valves. In addition to the cyclic change in pressure, a surge was noted when the valves were seated. Approximately 400 MSEC later the surge was registered at the "A" OTSG. The magnitude was a swing of at least 25 PSIG which lasted about 400 MSEC. See Figures 4 and 5.

The steam generator levels also showed upsets during the actual closing of the stop valves. Because the feedwater flow was not monitored during this time, it is not certain if this level swing was caused by an upset in feedwater demand or by the pressure surge.

4.2 Control Valve Tests -

The time required for this series of valve closings was approximately 150 sec. The unit was stable after the conclusion of the stop valve testing and power level of the reactor was 96%.

Refer to Figure No. 1 for valve configurations.

During operation of the valves, pressure increased at both the steam lines and back at the OTSG by approximately 10 PSIG. There was no sharp pressure surge noted on the instruments and no upset observed in the OTSG levels.

4.3 Intercept Valve Tests

The time required for this series of valve closings was approximately 160 sec. The unit was stable after the conclusion of the control valve testing and the power level of the reactor was 96%.

During operation of these valves, no upsets were noted in either pressure or OTSG levels.

5.0 Conclusions

Based on the apparent pressure surge noted during the testing of stop valves 3 and 4 in the "A" steam line, further testing is required to identify the source and amplitude. At this time B&W is developing plans for this test.

6.0 Corrective Action

Revised procedures for stop valve testing have been implemented.

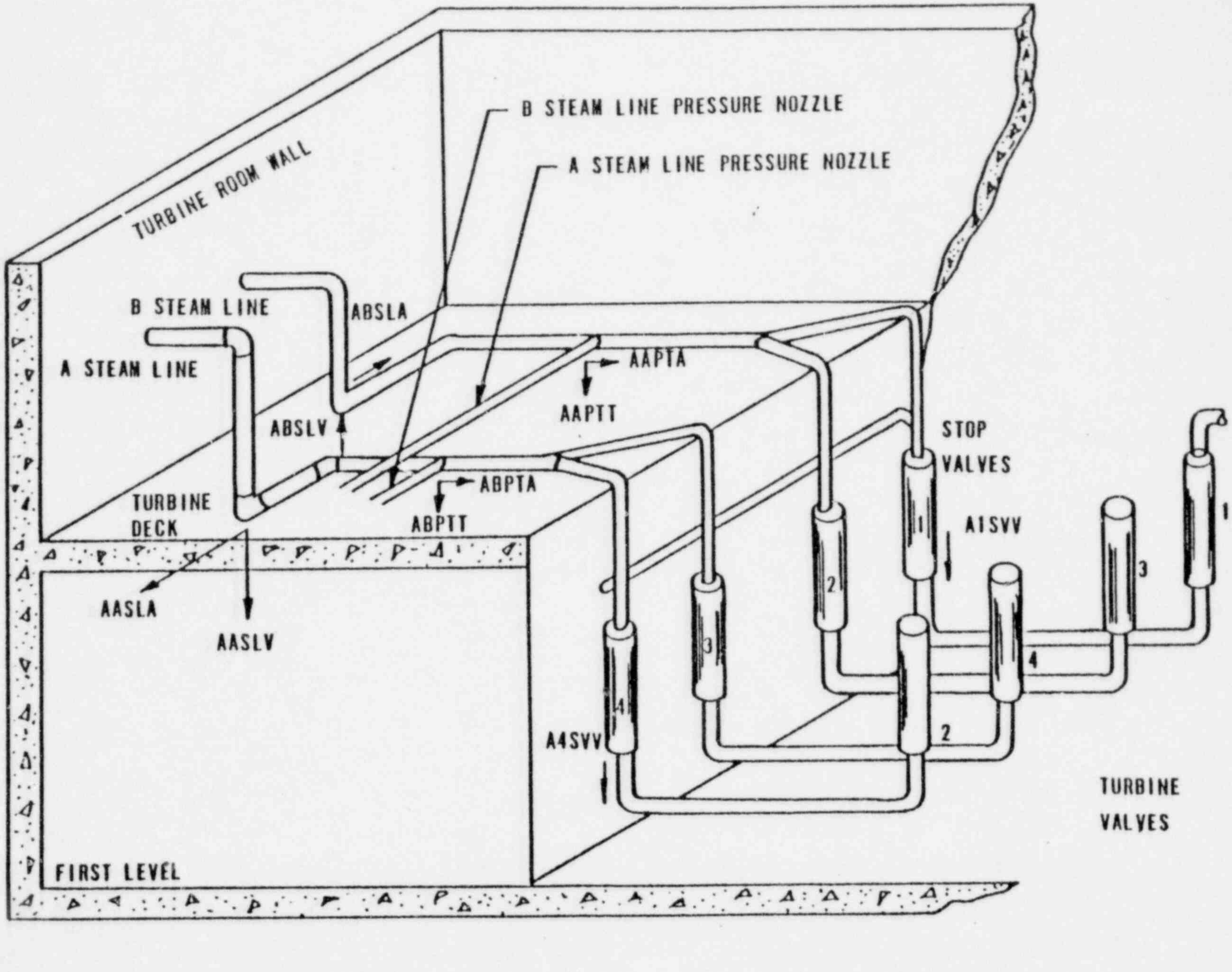

B STEAM LINE PRESSURE NOZZLE
A STEAM LINE PRESSURE NOZZLE
TURBINE ROOM WALL
B STEAM LINE
ABSLA
A STEAM LINE
AAPTA
AAPTT
ABSLV
STOP
VALVES
ABPTA
TURBINE
DECK
ABPTT
A1SVV
1
2
3
4
AASLA
AASLV
A4SVV
TURBINE
VALVES
FIRST LEVEL

FIGURE 1

FIGURE 1A: EXPLANATION FOR FIGURES 2-5

1.0 Legend

From left to right:

A1 Steam Generator Outlet Pressure
A Main Steam Line Pressure (at stop valve)
B1 Steam Generator Outlet Pressure
B Main Steam Line Pressure (at stop valve)

2.0 Span

For each of the four pressures, the span is 100 PSIG, with each small division equal to 2 PSIG.

3.0 Midpoint

A1 SGO = 903.3 PSIG
A MSP = 887.4 PSIG
B1 SGO = 903.9 PSIG
B MSP = 887.0 PSIG

4.0 Chart Speed

25 MM/Sec, or each major division = 0.2 sec.

5.0 Magnitude

Increasing pressure is to the left of midpoint
Decreasing pressure is to the right of midpoint.

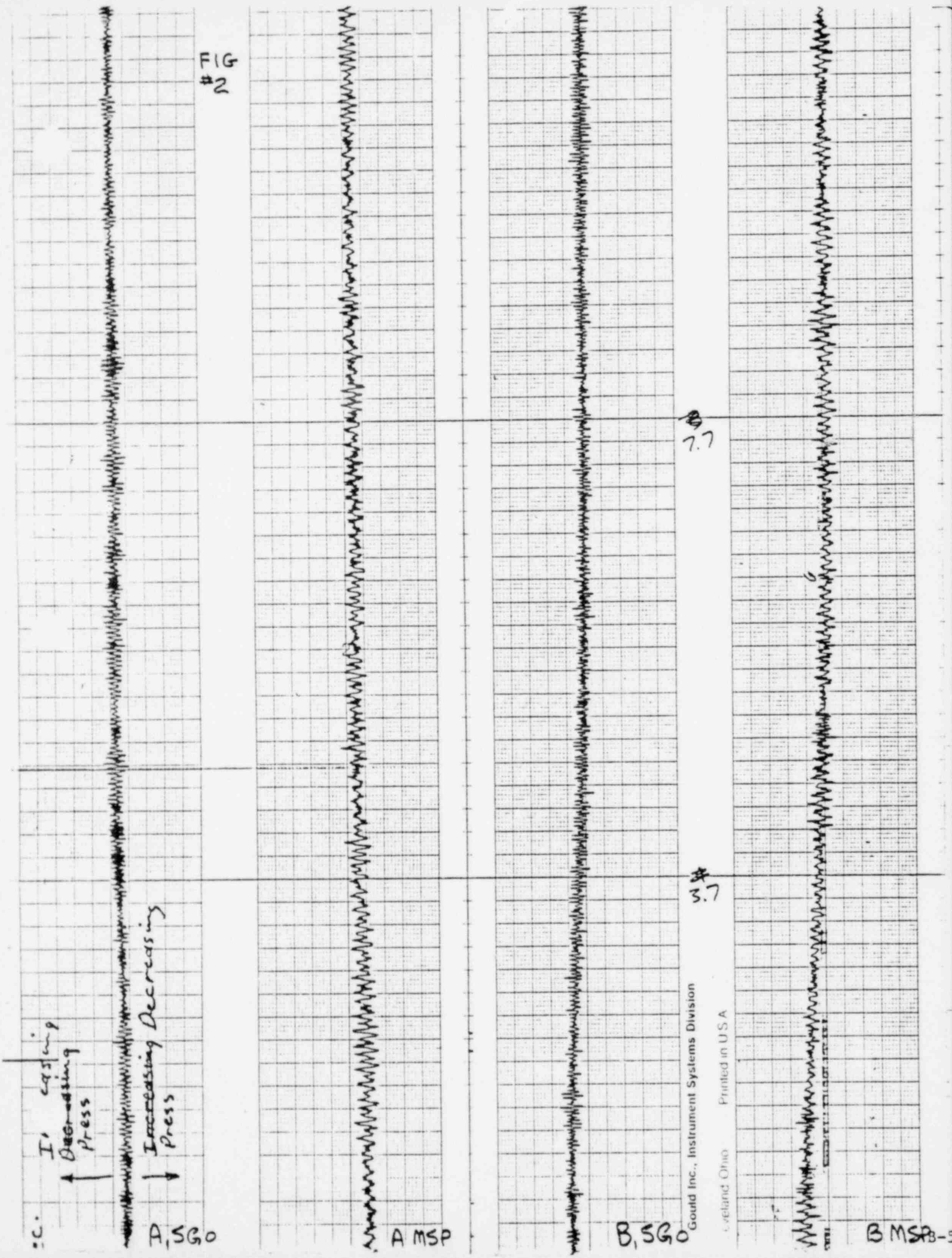


FIG #2
I' casing
Decreasing press
Increasing Decreasing Press
A,SGo
A MSP
7.7
3.7
B,SGo
Gould Inc., Instrument Systems Division
Printed in U S A
B MSP
B-5

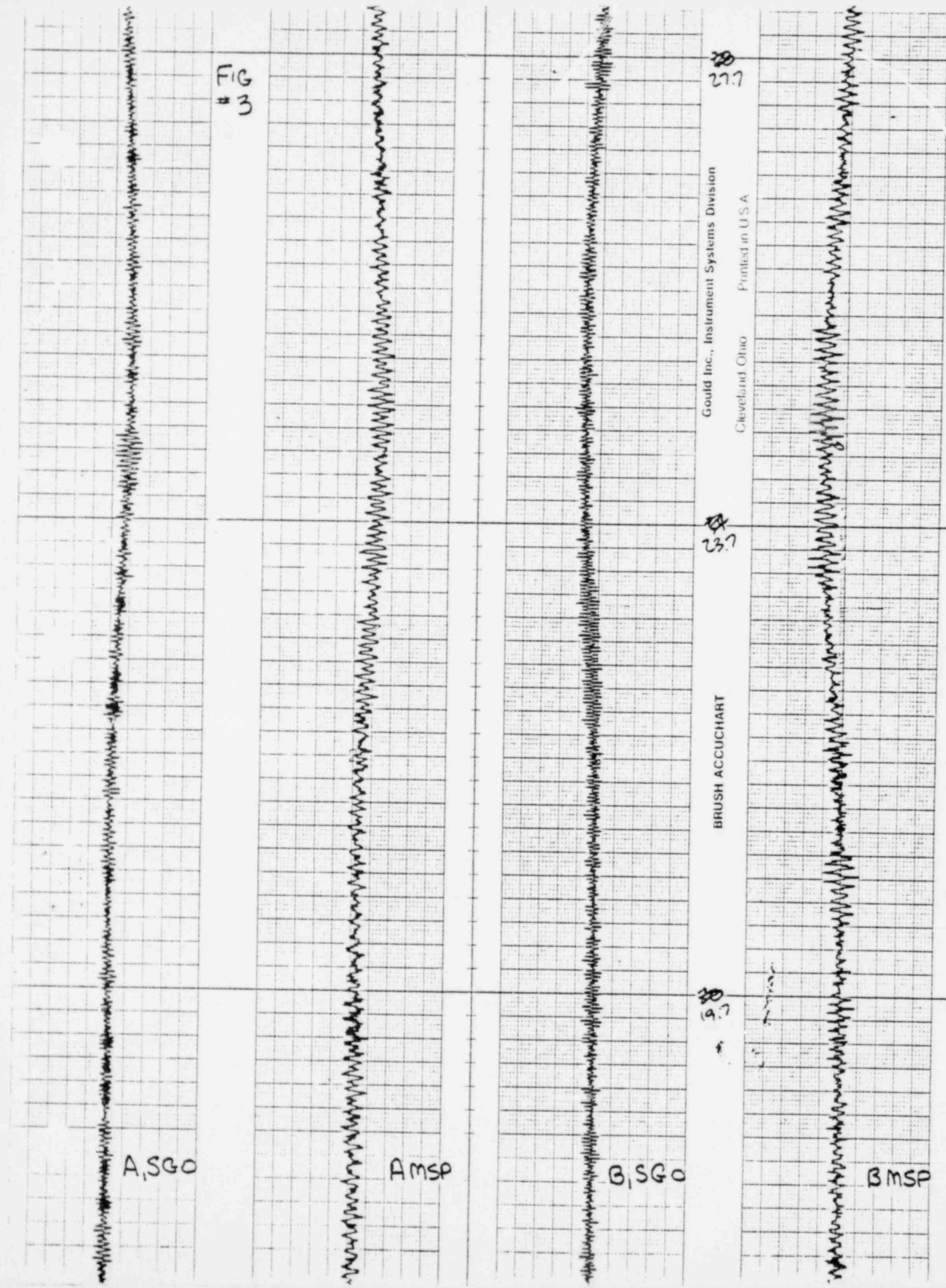


FIG
#3
27.7
23.7
19.7
Gould Inc., Instrument Systems Division
Cleveland Ohio
Printed in U.S.A
BRUSH ACCUCHART
A,SGO
AMSP
B,SGO
BMSP

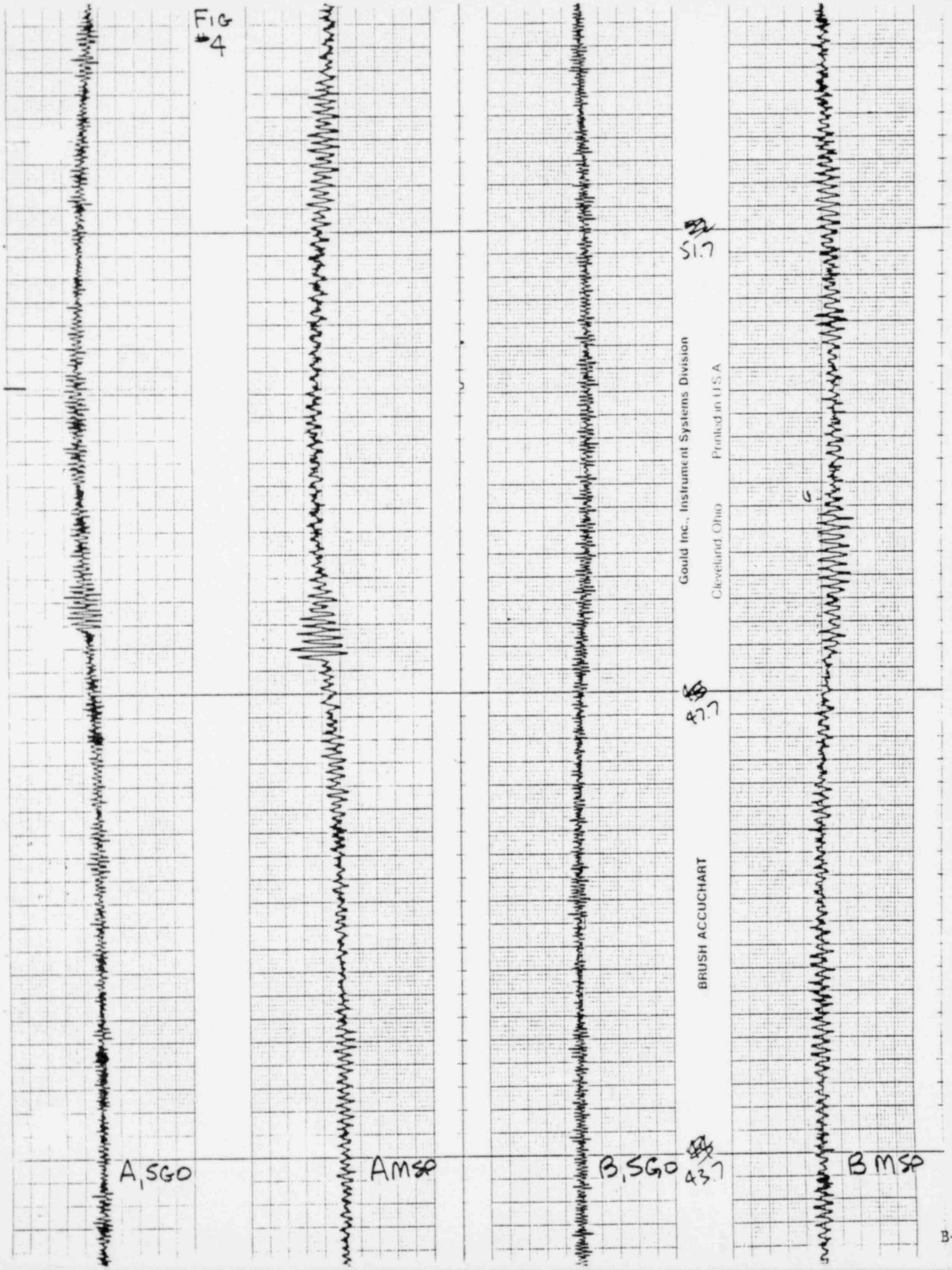


FIG #4
51.7
47.7
43.7
A,SGO
AMSP
B,SGO
BMSP
Gould Inc., Instrument Systems Division
Cleveland Ohio
Printed in U.S.A
BRUSH ACCUCHART

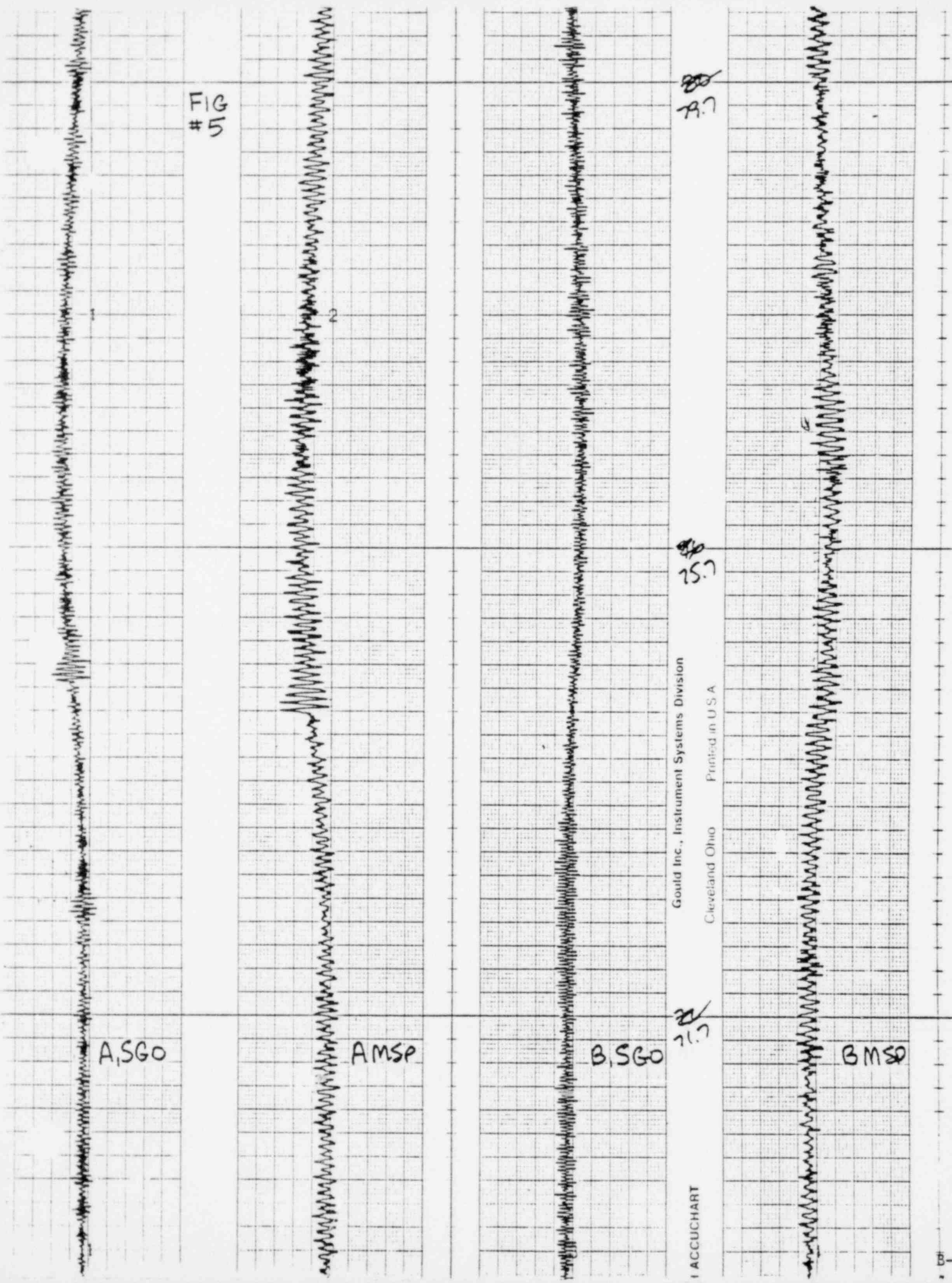


FIG #5
~~80~~ 79.7
~~76~~ 75.7
~~72~~ 71.7
A,SGO
AMSP
B,SGO
BMSP
Gould Inc., Instrument Systems Division
Cleveland Ohio Printed in U S A
ACCUCHART

APPENDIX C

SUMMARY OF TURBINE

STOP VALVE TEST PERFORMED ON

MARCH 18, 1977

OCONEE NUCLEAR STATION

STOP VALVE TEST - MARCH 18 & 19, 1977

Unit 1 - B&W Instrumentation

1.0 Purpose

The purpose of the measurement program conducted on the A and B OTSG at Oconee 1 was to determine if the pressure transmitters in the main steam line responded to a pressure pulse generated by the closure of the stop valves.

2.0 References

2.1 Babcock & Wilcox Company Report of April 8, 1977

2.2 P.O. 122A-1 - Main Steam System

2.3 P.O. 122B-2 - HP and LP Exhaust

2.4 0 422 N11 - Instrument Detail of Main Steam Lines

2.5 TP 1B 0270 32 - Stop Valve and Control Valve Test Procedures

3.0 Description

Accelerometers were utilized at the stop valves, steam line pressure transmitters, steam line elbow in turbine room and on the "A" and "B" OTSG. The complete list of instrumentation is listed in the appendix of this report. Data was recorded on three magnetic tape recorders, which were returned to Lynchburg, Virginia for complete analysis.

4.0 Evaluation of Results

Tables 4.1, 4.2, 4.3, and 4.4 identifies the data recorded during the stop valve testing.

The data shows that a mechanical shock pulse generated by closure of a shop valve causes a stress wave to be propagated in the steam line containing the stop valve. In the steam line that does not contain the exercised stop valve mechanical shock pulses were not observed.

The time delay between closure of a stop valve and the arrival of a shock pulse in another location is nearly proportional to geometric distances. The time delays increase and the signal dispersion increase as the geometric distance increases.

During the OTSG testing acceleration signals from each generator were monitored. Audible results indicated that no impact noises were produced by closure of the stop valve. However, the condition of the accelerometer

4.0 Evaluation of Results (cont'd)

system may have prevented observation of the metal-to-metal impact noises caused by stop valve tests. The LPM on the A OTSG had only one operable channel; and, the LPM on the B OTSG was made to function only by grounding the input signal at 5 sec. intervals.

The pressure in the steam generator either increases or decreases, depending on which stop valve is closed. Furhter, these figures show that closure of the stop valve causes only one very discernible pulse in the acceleration. But no sharp pulse is registered in the pressure time history.

5.0 Conclusions

As a result of acceleration and pressure measurements made during valve tests at Oconee 1, the following conclusions are made:

1. Transient behavior of pressure measurements in the steam lines is correlated with closure of the stop valves. The pressure change is less than or equal to 12 psi at 95% power.

2. The transient response of the pressure transmitter, when a stop valve is closed, indicates a highly damped second order system.

3. The transient behavior of the pressure transmitters results from changes in the pressure and does not result from mechanical shock.

4. No metal-to-metal sounds were observed on the LPM accelerometers during any valve testing. However, the poor operability of accelerometers in the LPM system may have obscured the metal-to-metal impact noise.

6.0 Corrective Action

Further testing is required on Unit 2 after unit return to service after refueling.

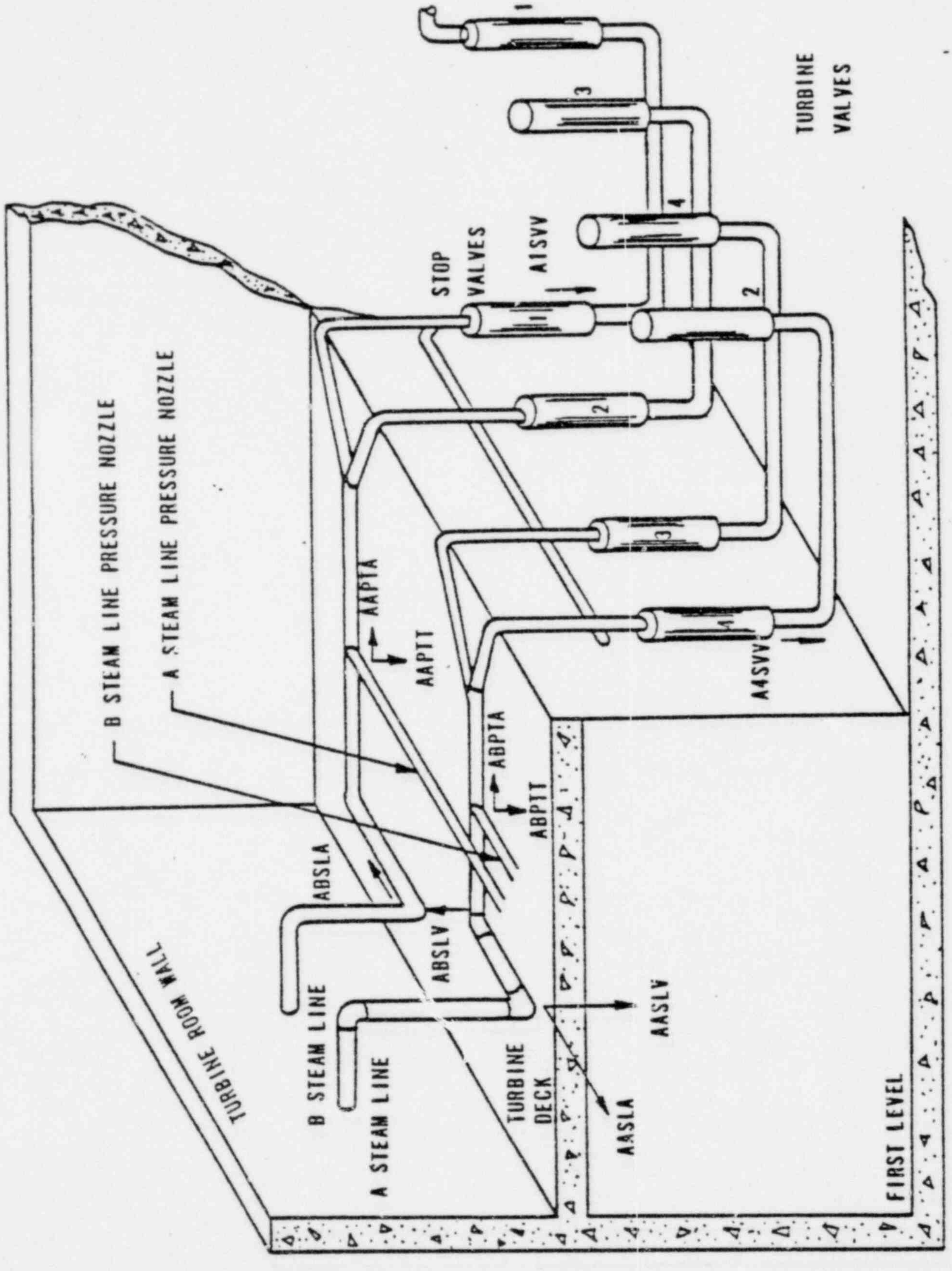


FIGURE 2.1 ACCELEROMETER LOCATIONS

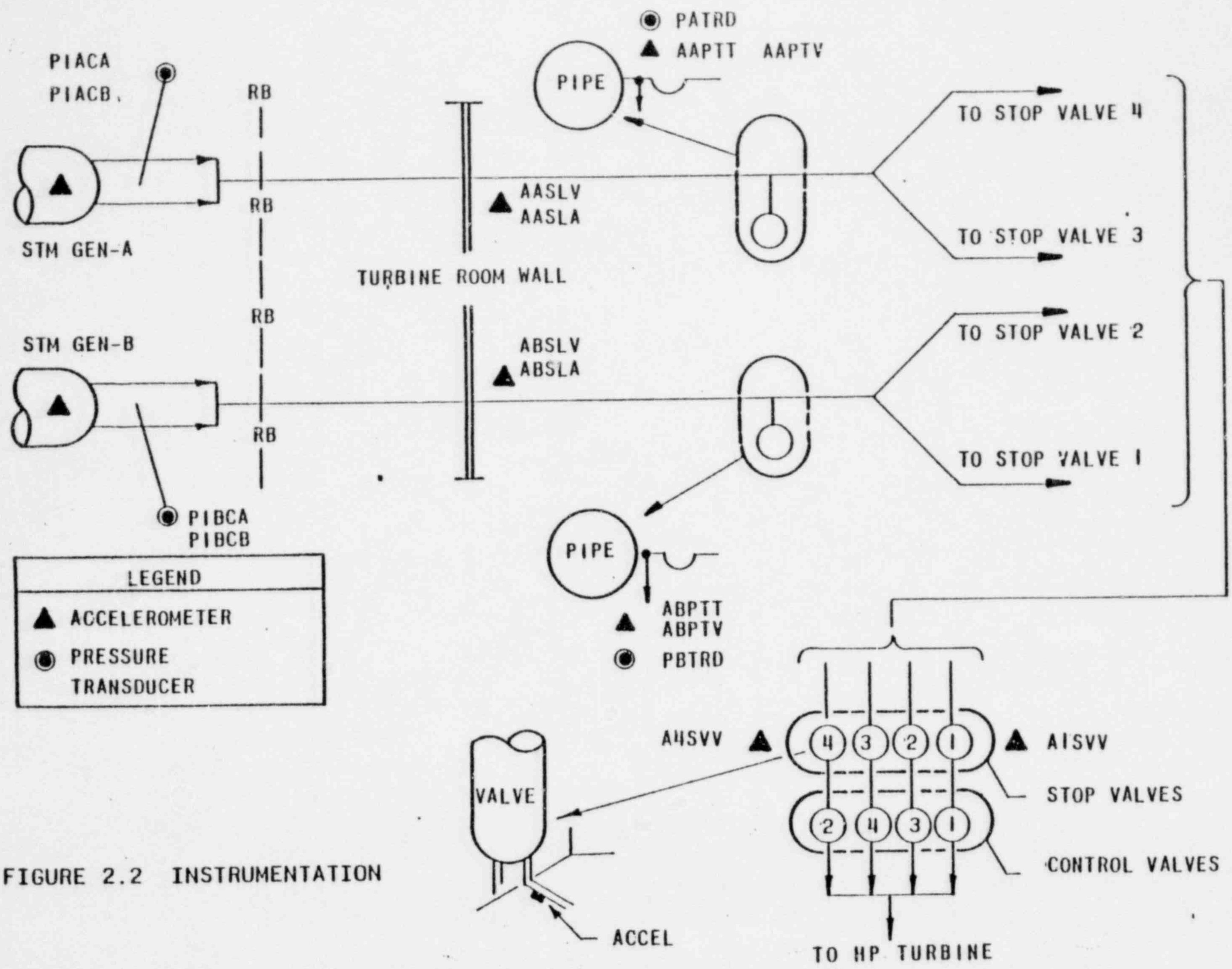


FIGURE 2.2 INSTRUMENTATION

TABLE 3.2c SCALE FACTORS

Tape Recorder 1

SENSOR	SCALING FACTOR
P1BCA	30 psi/v
P1BCB	15 psi/v
PATRD	15 psi/v
PBTRD	37.5 psi/v
A1AVR	3 g/v
A1BCR	3 g/v
AASLT	30 g/v
ABSLT	30 g/v
AAPTT	1000 g/v
A1SVV	1000 g/v
A4SVV	1000 g/v

Tape Recorder 2

SENSOR	SCALING FACTOR
P1ACA	30 psi/v
P1ACB	30 psi/v
PATRD	15 psi/v
PBTRD	37.5 psi/v
P1BCA	30 psi/v
P1BCB	15 psi/v
AASLA	30 g/v
ABSLB	30 g/v
AAPTA	1000 g/v
ABPTA	1000 g/v
A1SVV	1000 g/v
A4SVV	1000 g/v

Tape Recorder 3

SENSOR	SCALING FACTOR	RANGE
FWFLA	$3x10^6$ lb/hr/v	-1 to 1v
FWFLB	$3x10^6$ lb/hr/v	-1 to 1v
FWDMA	$3x10^6$ lb/hr/v	-1 to 1v
FWDMB	$3x10^6$ lb/hr/v	-1 to 1v
SGLA1	146 in/v	-1 to 1v
SGLB1	146 in/v	-1 to 1v
PSTCH	1500	0.2 to 1v
P1SHP	1000	0.2 to 1v
DBSV1		-20mv to 20mv
DBSV2		0 to 50mv
DBSV3		-20 to 120mv
DBSV4		-20 to 20mv

TABLE 3.1 SENSOR DESIGNATION

Sensor Identifier	Location
A1AVR	Accelerometer on vent line of 1A OTSG in approximately the radial direction
A1BVR	Accelerometer on vent line of 1B OTSG in approximately the radial direction
AASLT	Accelerometer on the A main steam line in the tangential direction
AASLA	Accelerometer on the A main steam line in the axial direction
ABSLT	Accelerometer on the B main steam line in the tangential direction
ABSLA	Accelerometer on the B main steam line in the axial direction
AAPTT	Accelerometer on the A pressure transmitter in tangential direction
AAPTA	Accelerometer on the A pressure transmitter in axial direction of the main steam line
ABPTT	Accelerometer on the B pressure transmitter in the tangential direction
ABPTA	Accelerometer on the B pressure transmitter in the axial direction of the main steam line
A1SVV	Accelerometer on the number 1 stop valve in the vertical direction
A4SVV	Accelerometer on the number 4 stop valve in the vertical direction
P1ACA	Pressure transmitter on the 1A OTSG in the containment-differential - A Leg
P1BCA	Pressure transmitter on the 1B OTSG in the containment-differential - A Leg
PATRD	Pressure transmitter on the A steam line in the Turbine Room - differential
PBTRD	Pressure transmitter on the B steam line in the Turbine Room - differential
P1ACB	Pressure transmitter on the 1A OTSG in the containment-differential - B Leg
P1BCB	Pressure transmitter on the 1B OTSG in the containment-differential - B Leg
FWFLA	Feedwater Flow into the A OTSG
FWFLB	Feedwater Flow into the B OTSG
FNDMA	Feedwater Demand for A OTSG
FWDMB	Feedwater Demand for B OTSG
SGLA1	Water Level in the A OTSG
SGLB1	Water Level in the B OTSG
PSTCH	Pressure in the steam chest
P1SHP	Pressure in the first high pressure stage of the turbine

TABLE 4.1 DATA SUMMARY-STOP VALVE TEST

STOP VALVE	PROCESS PARAMETER FEED WATER FLOW A lb/hr x10^5	FEED WATER FLOW B lb/hr x10^5	FEED WATER DEMAND A lb/hr x10^4	FEED WATER DEMAND B lb/hr x10^4	OTSG LEVEL A in.	OTSG LEVEL B in.	
1	+1.50	+3.00	-3.00	-2.25	-	+3.65	
2	+1.50	+2.63	+5.25	-3.75	-7.30*	-3.65	
3	+2.25	+1.88	-	-2.25	-3.65*	±1.83	65% PWR
4	+3.00	+3.00	-1.35	+11.3	±3.65	±1.83	
1	+4.13	-3.75	+15.0	-18.8	-25.6*	±3.65	
2	+4.13	-4.50	+18.8	-15.0	-18.3*	±3.65	95% PWR
3	+5.63	+4.13	-22.5	+22.5	-7.30*	-11.0	
4	+6.38	+5.25	-22.5	+22.5	+25.6*	-11.0	

TABLE 4.2 DATA SUMMARY-STEADY STATE

	FEED WATER FLOW A lb/hr x10^5	FEED WATER FLOW B lb/hr x10^5	FEED WATER DEMAND A lb/hr x10^4	FEED WATER DEMAND B lb/hr x10^4	OTSG LEVEL A in.	OTSG LEVEL B in.
65*	34.5	30.8	242	259	172	199
80	50.3	37.9	82.5	191	108	175
95*	52.1	48	60	82.5	201	131
	52.5	48	60	90	223	130

*Data From Stop Valve Test

+ = Greater Than Mean   ± = Identical Changes

- = Less Than Mean   * = Large Error in Data Readings

TABLE 4.3 DATA SUMMARY-TURBINE CONTROL VALVE

CONTROL VALVE	FEED WATER FLOW A lb/hr $x10^5$	FEED WATER FLOW B lb/hr $x10^5$	FEED WATER DEMAND A lb/hr $x10^4$	FEED WATER DEMAND B lb/hr $x10^4$	OTSG LEVEL A in.	OTSG LEVEL B in.	
1	-5.25	-4.28	+41.3	+15.0	12.8	±3.65	65% PWR
2	-3.00	-2.25	22.5	±7.50	12.8	+1.83	
1	±1.50	-2.25	+1.50	+1.13	+9.13*	+7.30	
2	-3.00	-1.50	+2.25	+1.88	+12.8*	+7.30*	92% PWR
3	±1.50	±1.50	-7.50	±1.13	+5.48*	+5.48*	

*Data From Stop Valve Test

TABLE 4.4 DATA SUMMARY-STOP VALVE TEST

STOP VALVE	A OTSG STEAM LINE A Psi	A OTSG STEAM LINE B Psi	B OTSG STEAM LINE A Psi	B OTSG STEAM LINE B Psi	MAIN STEAM LINE A Psi	MAIN STEAM LINE B Psi	
1	-9.75	-9.00	+9.00	+8.25	-4.88	+9.38	
2	-9.75	-9.75	+9.00	+8.63	-5.25	+9.38	
3	+12.00	+11.25	-9.75	-8.63	±1.88	-6.56	95%
4	+6.00	+12.00	-12.00	-9.38	±1.88	-12.19	