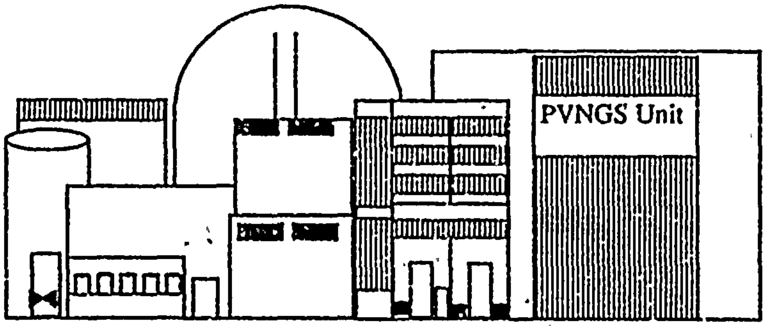
Attachment 2

Stavasoli



EQUIPMENT ROOT CAUSE OF FAILURE ANALYSIS REPORT

Category 1 Investigation
IIR 2-3-0112
Action 24

UNIT 2 STEAM GENERATOR TUBE RUPTURE

Event Date
March 14, 1993

PALO VERDE NUCLEAR GENERATING STATION

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TABLE OF CONTENTS

TABLE OF CONTENTS
(cont)

TABLE OF CONTENTS
(cont)

SECTION PAGE

TABLE OF CONTENTS
(cont)

TABLE OF CONTENTS
(cont)

TABLE OF CONTENTS
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I. EXECUTIVE SUMMARY

The Palo Verde Nuclear Generating Station (PVNGS) Unit 2 experienced a steam generator tube rupture (SGTR) in Steam Generator 22 (SG 22) on March 14, 1993 at 0434. At the time, the unit was operating at 98% power. The plant operators manually tripped the reactor, declared an Unusual Event which was subsequently upgraded to an Alert, and entered the PVNGS Functional Recovery Procedure to mitigate the event. The plant was cooled down and depressurized, and the event was terminated when Mode 5 was achieved at 0556 on March 15, 1993. The overall response to the event effectively mitigated the consequences of the steam generator tube rupture.

A Steam Generator Tube Rupture Task Force was formed by PVNGS to evaluate the conditions which led to the tube failure. The team was staffed with senior APS personnel and technical staff as well as industry consultants to develop the response and recovery efforts and to ensure that the necessary corrective actions were implemented in a complete and adequate manner.

A revised eddy current testing (ECT) program was initiated after visual and ECT examination identified the location and orientation of the tube failure (R117C144) in SG 22 (see Figures I-a and I-b). Axial crack indications at freespan and eggcrate support locations were found on multiple tubes in the upper region of the tube bundle. The Task Force, based on ECT evidence of outside diameter (OD) initiated axial cracking, assembled a list of possible failure modes in order to develop action plans for ECT, tube pull selection, engineering analysis, and laboratory techniques.

Specifically, eight tubes were removed (including the lower portion of the ruptured tube) from SG 22 for metallurgical and chemical examinations. The examination showed that tube R117C144 ruptured due to intergranular attack/intergranular stress corrosion cracking (IGA/IGSCC) in an alkaline-to-caustic with sulfate environment associated with freespan deposits. The detection of cold working due to scratched areas associated with long defects on tube R105C156 suggests that a cold worked surface area may have been present which when combined with the freespan crevice deposits, led to preferred IGA and subsequent early crack initiation.

Microstructural evidence showed that tube R117C144 would have the least resistance to IGSCC compared to other tubes examined. However, the effect is considered to be secondary based on tube R127C140 results which showed a throughwall crack at the 07H support location that was associated with surface damage but had a lower concentration of deposits and more favorable microstructure.

Freespan tube degradation found in tubes R105C156 and R103C156 is concluded to be consistent with the damage mechanism found on tube R117C144. The crevice environment was concluded to be alkaline-to-caustic with sulfate formed under freespan crevice deposits. These tubes also had marginal microstructures but not to the degree of the ruptured tube. Of these two tubes, tube R105C156 was the most severely degraded.

Freespan tube R117C40, piece 17 was found to have IGA/IGSCC associated with ridge deposit buildup. The average and deepest penetrations were 27% and 61%, respectively, demonstrating that scratches are not required for IGA/IGSCC to occur.

Additionally, a comprehensive review of fabrication, operation and chemistry history was performed to determine if an anomaly contributing to the failures existed. Industry-developed thermal-hydraulic codes were also utilized to evaluate steam quality and deposit distribution in the tube bundle. Based on the information resulting from these activities, the Task Force developed the most probable causal factors for tube degradation which led to the failure of tube R117C144.

After considerable evaluation the Root Cause of Failure (RCF) investigation determined the failure mechanism leading to the SGTR event was due to IGA/IGSCC which occurred as a result of tube-to-tube crevice formation. The crevice, together with the consequential heat flux, led to an aggressive environment under a tenacious ridge deposit. As a consequence a long deep crack, initiating under the ridge deposit, led to loss of structural integrity under normal operating conditions. Several additional contributing factors such as increased sulfate levels due to resin intrusion, a less than standard microstructure in R117C144, the likelihood of cold working due to tube surface scratches, and increased susceptibility to contaminant concentration in the upper region of the tube bundle were identified by the Task Force. Since it was not possible to weight the relative importance of each contributor, APS intends to continue the investigative effort to address each item.

Corrective actions have been developed to mitigate the effects of the conditions which contribute to IGA/IGSCC. These include monitoring and controlling crevice conditions, minimizing contaminant ingress, and optimizing contaminant removal mechanisms. In order to provide prompt operator action in the event of increasing primary-to-secondary leak rate, enhancements were made to leak rate monitoring and evaluation programs and radiation monitoring systems.

II. EQUIPMENT DESCRIPTION

A. STEAM GENERATOR DESIGN

Each of the three Palo Verde units has two steam generators that separate the reactor coolant system (RCS) (radioactive water) and the main steam and secondary plant (nonradioactive steam/water).

The steam generator is a shell and U-tube heat exchanger with an integral economizer. It operates with reactor coolant on the tube side and secondary coolant on the shell side. During normal operation, reactor coolant leaving the core of the reactor vessel enters the two "hot legs," one per loop, and flows to the steam generators. Normal hot leg temperature is 621.2°F. This hot reactor coolant enters the steam generator through the inlet nozzle in the steam generator primary head. Primary (reactor) coolant flows through the U-tubes giving up its heat to the secondary feedwater in the shell side of the steam generator. The heat added by the reactor coolant causes the feedwater (secondary coolant) to boil thus generating steam for turbine operation. The primary (reactor coolant) and secondary (feedwater and steam) systems are intended to be separated by the steam generator tubes, to prevent radioactive contamination of the secondary system.

The design and fabrication of the steam generators is within the scope of CESSAR. The NRC's evaluation of the steam generators is contained in the CESSAR SER, Section 5.4.2 (NUREG-0852).

General Design Criterion 32, "Inspection of Reactor Coolant Pressure Boundary," Appendix A of 10 CFR Part 50, requires, in part, that components which are part of the reactor coolant pressure boundary or other components important to safety be designed to permit periodic inspection and testing of critical areas for structural leaktight integrity.

The components in the steam generator are classified as ASME Boiler and Pressure Vessel Code Class 1 and 2 depending on their location in either the primary or secondary coolant systems respectively. The PVNGS steam generators were designed to permit inservice inspection of the Class 1 and 2 components, including individual tubes. The design aspects that provide access for inspection and the proposed inspection program follow the recommendations of RG 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," Revision 1 and NUREG-0212, "Standard Technical Specification for Combustion Engineering Pressurized Water Reactors," Revision 1.

The components of the PVNGS Steam Generator comply with the requirements of Section XI of the ASME Code, with respect to the inspection methods to be used, provisions for a baseline inspection, selection and sampling of tubes, inspection intervals, and actions to be taken in the vent defects are identified.

A. STEAM GENERATOR DESIGN (cont.)

The evaluation and analysis of a Steam Generator Tube Rupture accident is presented in the CESSAR SER, Section 15.3.7.

The Surveillance Requirements, Limiting Condition for Operation, Bases, and Procedures and Programs pertaining to the Steam Generators are located in the appropriate sections of the Technical Specifications.

1. Design Data and Parameters

The steam generators are vertical tube and shell heat exchangers approximately 68 feet in height with a steam drum diameter of 20 feet. The steam generator arrangement is shown in Figure II.A.1.a.

The steam generators are designed to transfer 3817 MWt from the reactor coolant system to the secondary system, producing approximately 17.2 x 10^6 LBM/HR of 1070 psia saturated steam when provided with 450°F feedwater. Moisture separators and steam dryers in the shell side of the steam generator limit moisture content of the steam to 0.25% wt during normal operation at full power. The steam generator design parameters are provided in Table II.A.1.

The primary chamber is located at the bottom of the steam generator. It forms part of the RCS pressure boundary and directs reactor coolant flow through the steam generator. The primary chamber is divided into two plenums (inlet and outlet) by a divider plate and stay cylinder.

The stay tube is a hollow, cylindrical tube located in the center of the steam generator. It aids in separating the primary chamber inlet and outlet plenums, the economizer and evaporator regions on the steam generator secondary side, and supports the tube sheet. The divider plate is attached to the stay tube using tongue and groove joints to allow flexibility between it, the primary chamber, and the tube sheet.

One nozzle is provided in the inlet plenum and two in the outlet. Flow from the associated reactor coolant loop hot leg enters through the 42 inch inside diameter (ID) inlet nozzle, passes through the tube sheet and U-tubes, and returns to the reactor coolant pump suction legs via the two 30 inch ID outlet plenum nozzles (i.e., a nozzle is provided for each associated reactor coolant pump suction pipe).

Two 16-inch primary manways and four instrument nozzles are provided. The primary chamber is constructed of carbon steel with stainless steel cladding on inner surfaces to minimize corrosion. Its design temperature and pressure are 650°F and 2500 psia, respectively.

II. EQUIPMENT DESCRIPTION (CONT.)

A. STEAM GENERATOR DESIGN (cont.)

1. Design Data and Parameters (cont.)

The secondary side of the steam generator consists of two cylindrical shells, joined to the steam drum by a conical section. The secondary side shell forms the pressure boundary between the steam generator secondary side and containment atmosphere, and contains the steam generator internals. The shell is constructed of carbon steel and has a design temperature and pressure of 575°F and 1270 psia respectively. It consists of:

a. Lower and intermediate shell

b. A transition cone

c. A steam drum

d. The head.

The lower and intermediate shell surrounds the steam generator evaporator and economizer sections. It has an inside diameter of 178 inches and is provided with the following penetrations:

a. Economizer feedwater nozzles, 14 inch (2)

b. Hand holes, 6 inch (2) (inspection points)

c. Hand holes, 7 inch (2) installed during 42R4 @ tubesheet level.

d. Level instrument nozzles, 0.75 inch (4)

e. Economizer blowdown nozzle, 2 inch (1)

The transition cone also surrounds the steam generator evaporator section. It provides the changes in diameter from the intermediate shell to the steam drum. The transition cone is provided with the following penetrations:

a. Secondary manways, 16 inch (2)

b. Downcomer feedwater nozzle, 6 inch (1)

c. Level instrument nozzles, 0.75 inch (4)

A. STEAM GENERATOR DESIGN (cont.)

1. Design Data and Parameters (cont.)

The hemispherical head at the top of the steam generator is provided with two, 28 inch main steam outlet nozzles which are each connected to a main steam line. Each outlet nozzle includes an integral flow orifice which limits steam flow (to reduce containment peak pressure) in the event of a steam line rupture.

2. Material

The steam generator is constructed of low alloy steel (P3) pressure containing members and Inconel 600 tubing. The tubesheet is a 23.5 inch thick low alloy steel base, with 1/4 inch thick Inconel 600 cladding on the primary surfaces. The tubes are made of high temperature mill annealed Inconel 600. Supports are constructed of ferritic stainless steel. With the exception of the tube sheet and the scallop bars on the partial eggcrates, carbon steels do not come in direct contact with the tubes.

B. TUBE DESIGN

Each generator contains 11,012, three quarter inch outside diameter, Inconel 600 alloy tubes which make up the tube bundle. The average wall thickness of the tubes is 0.042 inch. Tubes are inserted into the tubesheet by a method known as explansion (explosive/expansion). The tube bundle is enclosed by a wrapper plate which forms the downcomer annulus just inside the shell. The top of the wrapper serves to support the separator deck.

The tubes are arranged in rows with all tubes in a given row having the same length. The rows are staggered, forming a triangular pitch arrangement as is shown in Figure II.B.a. The shorter tubes which have 180 inch bends are at the center of the tube bundle in the first 18 rows. All subsequent rows have double 90 inch bends. The vacant space (4-1/4 inches) between the tubes in the first row is called the tube lane which is open through the vertical legs of the tube bundle. The tube lane is the boundary between the hot leg side and the cold leg side of the secondary side of the steam generator.

C. INTERNAL SUPPORT STRUCTURES

The steam generator is of a stayed design to support the tubesheet, and as a result, the center of the tube bundle contains a cylindrical cavity. The tube supports are designed to provide support during operation or combined seismic/accident conditions while offering minium restrictions to steam/water flow in the tube bundle.

The steam generators were designed to ensure that critical vibration frequencies do not occur during either normal operation or abnormal conditions. The tubing and tubing supports were designed and fabricated with consideration given to secondary side flow induced vibrations. In addition, the steam generator assemblies were designed to withstand blowdown forces resulting from the severance of a steam nozzle.

There are four types of tube supports in the Palo Verde steam generators. Refer to Figure II.C.a for the locations of the tube supports.

1. Flow Distribution Plate (01H and 01C)

The flow distribution plate is the first horizontal support on both the hot and cold leg side of the steam generators. It is a "drilled hole" type of support. Cold feedwater enters a distribution box which uniformly admits water to the area under the cold leg flow distribution plate, and recirculation flow enters the area under the hot leg flow distribution plate. The flow distribution plate is perforated with holes that are sized to hydraulically distribute flow into the upper SG.

2. Horizontal Eggcrate Supports (02H-09H and 02C-09C)

Horizontal eggcrate supports are a diagonal eggcrate design, as shown in Figure II.C.2.a. They provide horizontal stabilization for the tubes within the tube bundle and are used from 02H through 09H and 02C through 09C. The top two horizontal eggcrate supports are referred to as partial supports as only a portion of the tubes pass through each one. The partial eggcrates are stiffened by a scallop bar welded onto the face of the eggcrate. (See Figure II.C.2.b Figure II.C.2.c.)

3. Batwings

Batwing stabilizers horizontally support the bends in the U-tubes. (See Figure II.C.3.a.) The purpose of these stabilizers, which are constructed of strips of steel, is to prevent tube-to-tube contact between columns rather than provide structural support for the tubes.

II. EQUIPMENT DESCRIPTION (CONT.)

C. INTERNAL SUPPORT STRUCTURES (cont.)

4. Vertical Straps

The vertical straps and associated support grids provide vertical support for the tubes in the horizontal run at the upper region of the generator. The support grids are hung from structural support straps that are attached to "I" beams in the upper head. In addition, several vertical supports float, that is, they are not attached to any "I" beams. That configuration provides vertical stabilization for the tubes. (See Figure II.C.4.a.)

II. EQUIPMENT DESCRIPTION (CONT.)

D. STEAM GENERATOR OPERATIONAL OVERVIEW

1. Flow Paths

The are two flow paths associated with the steam generators on the primary side (tube side) and the secondary (shell side). Reactor coolant enters the bottom of the steam generator through the single hot leg inlet nozzle, flows through the U-tubes, and exits through the two cold leg outlet nozzles. A vertical divider plate and stay cylinder separate the inlet and outlet plenums in the lower head.

The secondary (feedwater) flow paths (see Figure II.D.1.a) into the steam generator are via the downcomer and the economizer flow nozzles. The extent of flow through each path depends on the reactor power level of the operating unit for downcomer flow.

The feedwater ring distributes downcomer flow entering the steam generator from the upper feedwater nozzle. It consists of a pipe with ten "J" tube extensions and is located above the U-tube bundle, outside the wrapper plate. Downcomer flow enters the feed ring and is directed to the top of the moisture separator support plate, where it combines with moisture separated from the steam-water mixture, and drains to the downcomer annulus (between the wrapper plate and the secondary side shell). The "J" tubes minimize feed ring water hammer by minimizing the amount of water flashing to steam during shutdown periods. Auxiliary feedwater is injected via the downcomer nozzle during emergency conditions to prevent thermally shocking the U-tubes.

Economizer flow enters just above the tube sheet on the cold leg side of the steam generator. It increases steam generator efficiency by preheating incoming feedwater before the feedwater enters the evaporator section. The economizer consists of a flow distribution box and flow distribution plate. A divider plate separates it from the steam generator hot leg side. Feedwater is introduced to the economizer distribution box through two economizer nozzles.

The distribution box is (Figure II.D.1.b) of rectangular cross-section and encircles the cold leg side of the tube bundle below the flow distribution plate. Holes machined in the distribution box uniformly admit feedwater to the area under the distribution plate. The flow distribution plate is perforated to ensure uniform feedwater distribution in the economizer section.

D. STEAM GENERATOR OPERATIONAL OVERVIEW (cont.)

2. Blowdown

To minimize corrosion and solid deposit buildup, steam generator water chemistry must be maintained within specifications. Chemistry is controlled by feedwater chemical addition and steam generator blowdown. The steam generator is equipped with a blowdown system as depicted in Figures II.D.1.b and II.D.2.a. Both the hot leg side and the cold leg side (economizer) have this feature. Blowdown provides the ability to remove concentrated impurities from the steam generator, and thereby lessens the possibility of steam generator corrosion. A normal continuous blowdown of 0.2% main steaming rate (MSR) is maintained. Abnormal (1% MSR) and high capacity (10% MSR) blowdown are utilized as chemistry conditions dictate.

3. Steam Generator Level Control

The primary purpose of the Feedwater Control System (FWCS) is to maintain programmed SG levels. To accomplish this, the FWCS consists of a master controller and controllers for each of the main feedwater components: downcomer valve, economizer valve and Feedwater Pump Turbine (FWPT). The FWCS basically has two automatic control modes, single element and three element control. The modes are dependant on reactor power level.

At power levels below 15%, the single element is in control and uses only the SG level as an input. Also below 15% power, only the downcomer valve is regulated to maintain steam generator level. The economizer valve is closed and the FWPT speed is at minimum speed.

The economizer feedwater control valve position program is generated as a function of the flow demand signal. This valve position program is designed such that, during low flow operations (less than 15% reactor power), the economizer feedwater control valve is closed, allowing the downcomer valve to regulate flow. When reactor power goes above 15% (both FWCS sense greater than 15% reactor power), the economizer valve regulates flow. The valve program provides hysteresis in the position demand signal at low flow demand conditions. This prevents cycling of the valve and continued operation with a small valve opening. During high flow operation, pump speed control is the primary mechanism for regulating the feedwater flow rate. The downcomer feedwater control valve position program is also a function of the flow demand signal generated by the single-element or the three-element control system.

D. STEAM GENERATOR OPERATIONAL OVERVIEW (cont.)

3. Steam Generator Level Control (cont.)

When reactor power is greater than 15% (as sensed by both FWCS), the downcomer valve closes and the economizer valve starts to regulate the feedwater flow. When the flow demand signal increases further, the downcomer valve position demand program reopens the downcomer valve to a final predetermined position (approximately 60% open).

4. Steam/Moisture Separation

The steam/water mixture leaving the tube bundle area has a steam quality of approximately 30%-60%. The steam exiting the steam generators must have a quality of 99.75%. To remove the required moisture, the System 80 steam generators employ two stages of moisture separation - centrifugal separators and steam dryers.

The first phase is accomplished by 194 centrifugal separators. The System 80 moisture separators are provided with stationary spinner blades which impart a centrifugal motion to the steam/water mixture. The heavier water is thrown to the surface of the can deck where it passes through holes in the separators side. The remaining two-phase mixture flows upward to the top of the separator where additional moisture is removed by nine (9) layers of corrugated baffles. The moisture removed here drops back into the separator region and is recirculated though the steam generator via spillover from the can deck. (See Figure II.D.1.a.)

5. Steam Generator Circulation Ratio

The steam generator circulation ratio (CR) or recirculation ratio is defined as the total secondary fluid flow through the tube bundle divided by the steam output (or feedwater output), on a weight per unit time basis, during steady state operation. For the PVNGS steam generators, Combustion Engineering (CE) has calculated a CR of 3:1 for 100% power operation. Since in CE designed generators, the total secondary fluid flow remains nearly constant for steady state operation from 40% to 100% power, the PVNGS SGs varies at different power levels (i.e., CR is 6:1 for 50% power). Factors which influence the circulation ratio are:

a. Downcomer water level - higher water levels increase CR

b. Recirculation path pressure drop - higher delta-P decreases CR

c. Steam pressure - higher pressures decrease CR

d. Tube bundle diameter - larger diameter decreases CR

e. Primary moisture separator duty - higher duty decreases CR.

D. STEAM GENERATOR OPERATIONAL OVERVIEW (cont.)

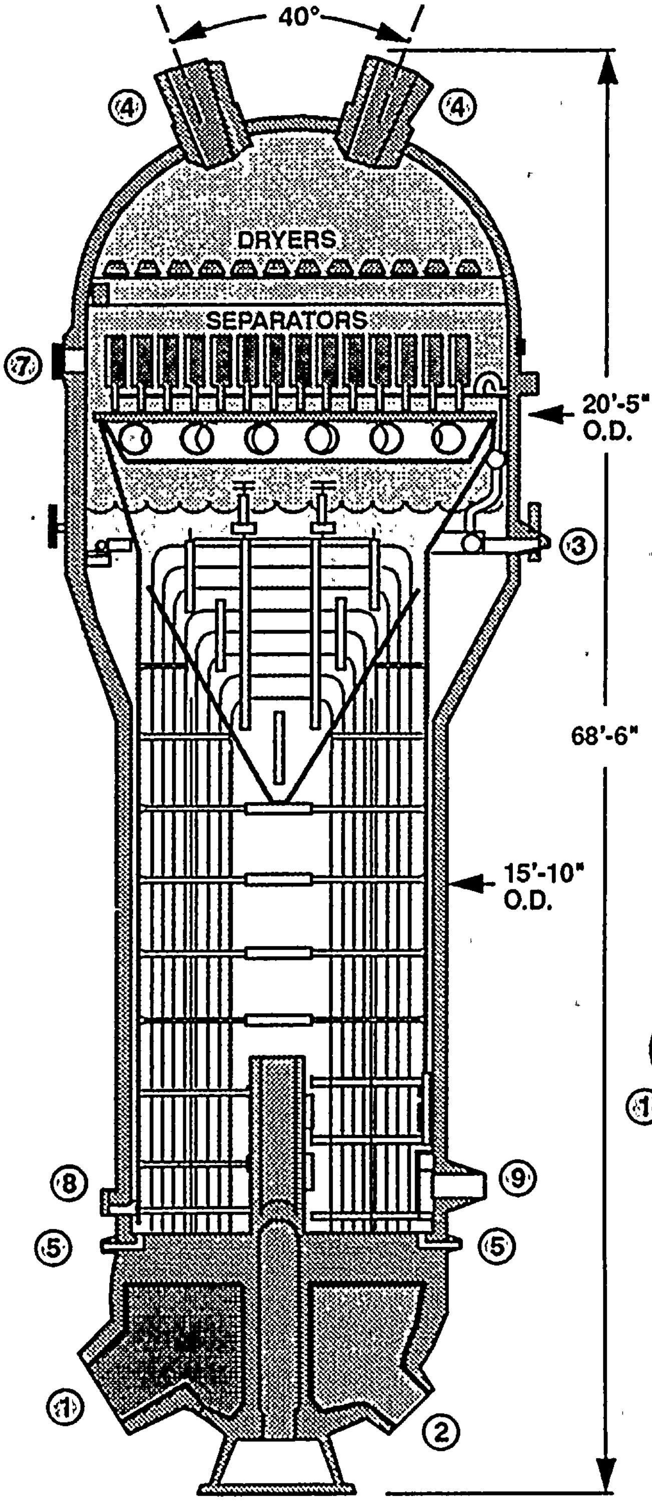
5. Steam Generator Circulation Ratio (cont.)

Typical industry circulation ratios range from 3:1 to 4:1. The lower range value for the System 80 steam generator is accounted for by its inherent design features. The controlling parameter for internal SG circulation is the difference in hydraulic head (feet of water at the average density) between the downcomer annulus as compared to the fluid in the tube bundle and above through the steam separators. When the total pressure drop within the recirculating flow path equals the driving head, equilibrium is attained. Since the secondary side of the steam generator operates in the saturated steam regime, higher steam pressure is associated with higher fluid saturation temperatures and corresponding lower liquid densities. Therefore, the downcomer driving head is reduced at higher steam pressures leading to a lower circulation ratio.

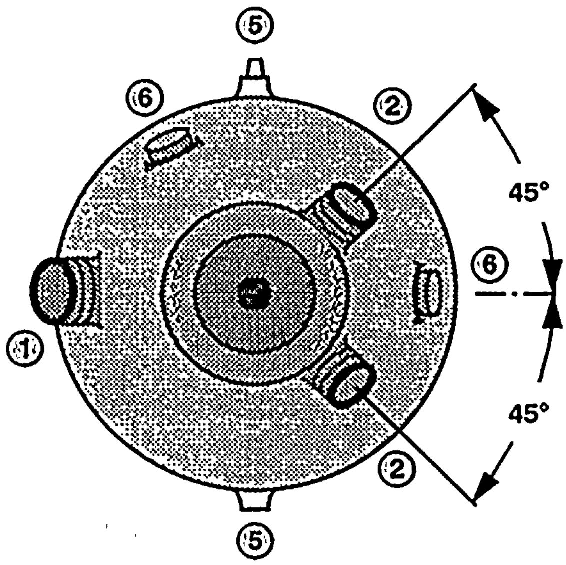
Additionally, based on comparative plant data developed by CE, if all other parameter are equal, larger diameter units have marginally lower circulation ratios than smaller units. This may be due to a greater amount of lateral cross flow (as opposed to axial flow) in the larger units. Finally, the moisture separators represent the highest single pressure drop in the recirculating flow path. Therefore, the relative duty (amount of moisture removed per separator) has a significant impact on the circulation ratio.

FIGURE II.A.1.a

SYSTEM 80 STEAM GENERATOR



NO.	SERVICE	NO. REQ'D
1	Primary Inlet	1
2	Primary Outlet	2
3	Downcomer Feedwater	1
4	Steam Outlet	2
5	Blowdown	2
6	Primary Manway	2
7	Secondary Manway	2
8	Handhole	2
9	Economizer Feedwater	2



BOTTOM VIEW OF STEAM GENERATOR

Table II.A.1

STEAM GENERATOR DATA

Quantity	2
Type	Vertical U-Tube
Number of Tubes per SG	11,012

1. Primary Side

Design Pressure	2500 psia
Design Temperature	650°
Design Thermal Power	3817 MW
Coolant Flow in Each Loop	8.2 x 10 lbm/hr
Normal Operating Pressure	2250 psia
Normal Operating SG Inlet Temperature	621.2°F
Normal Operating SG Outlet	564.5°F
Temperature Coolant Volume	2317 ft.

2. Secondary Side

Design Pressure	1270 psia
Design Temperature	575°F
Normal Operating Saturated Steam	
Pressure at 100% power	1070 psia
Normal Operating Steam Temperature	
at 100% Steam Flow per SG	8.59 x 10 lbm/hr
100% Steam Flow per SG	8.59 x 10 lbm/hr
Maximum Blowdown Flow	738,740 lbm/hr

3. Dimensions

Overall Height	817.5 inches
Steam Drum Diameter (OD)	266.5 inches
Lower Shell Diameter (OD)	189.5 inches
Dry Weight	1,428,900 pounds
Tube Diameter	0.75

SYSTEM 80 STEAM GENERATOR TUBES

TRIANGULAR PITCH CONFIGURATION

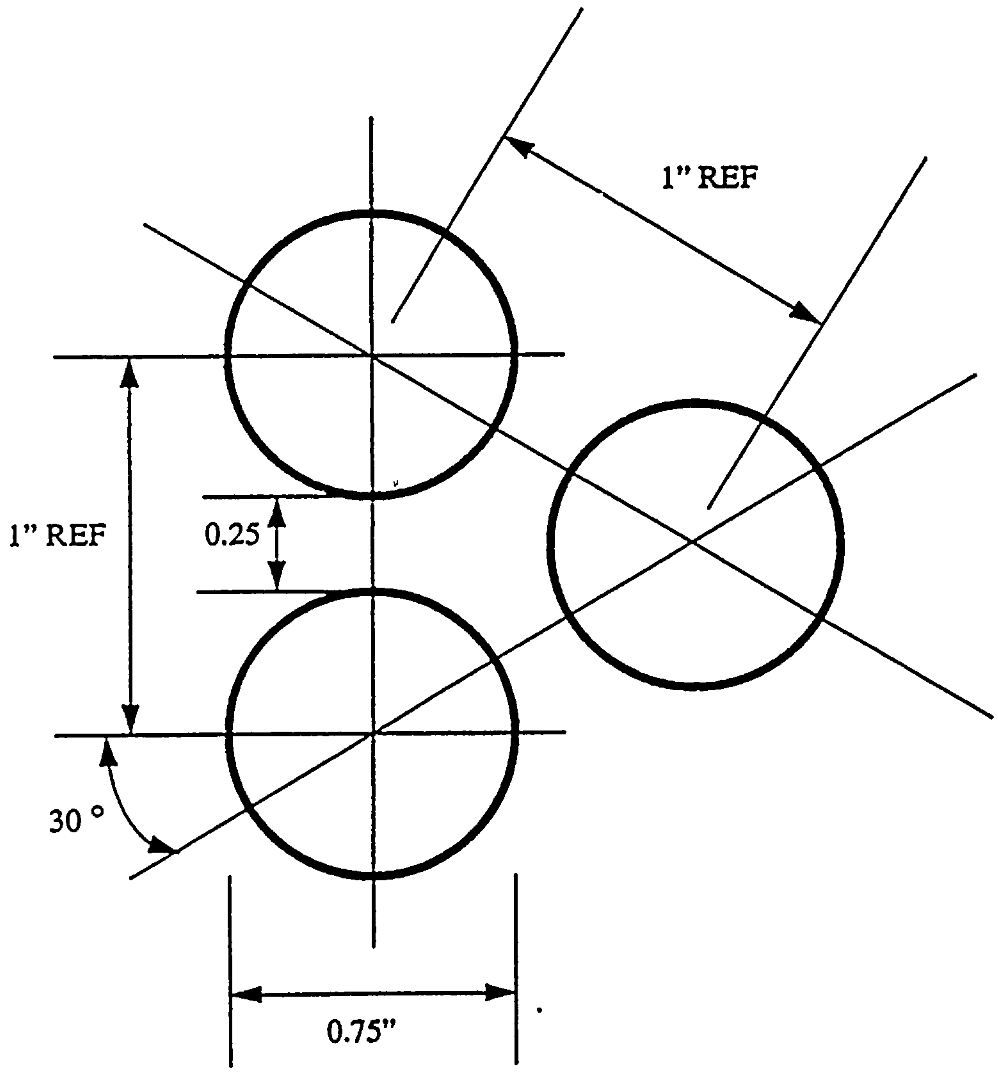


FIGURE II.B.a

STEAM GENERATOR TUBE SUPPORT DIAGRAM

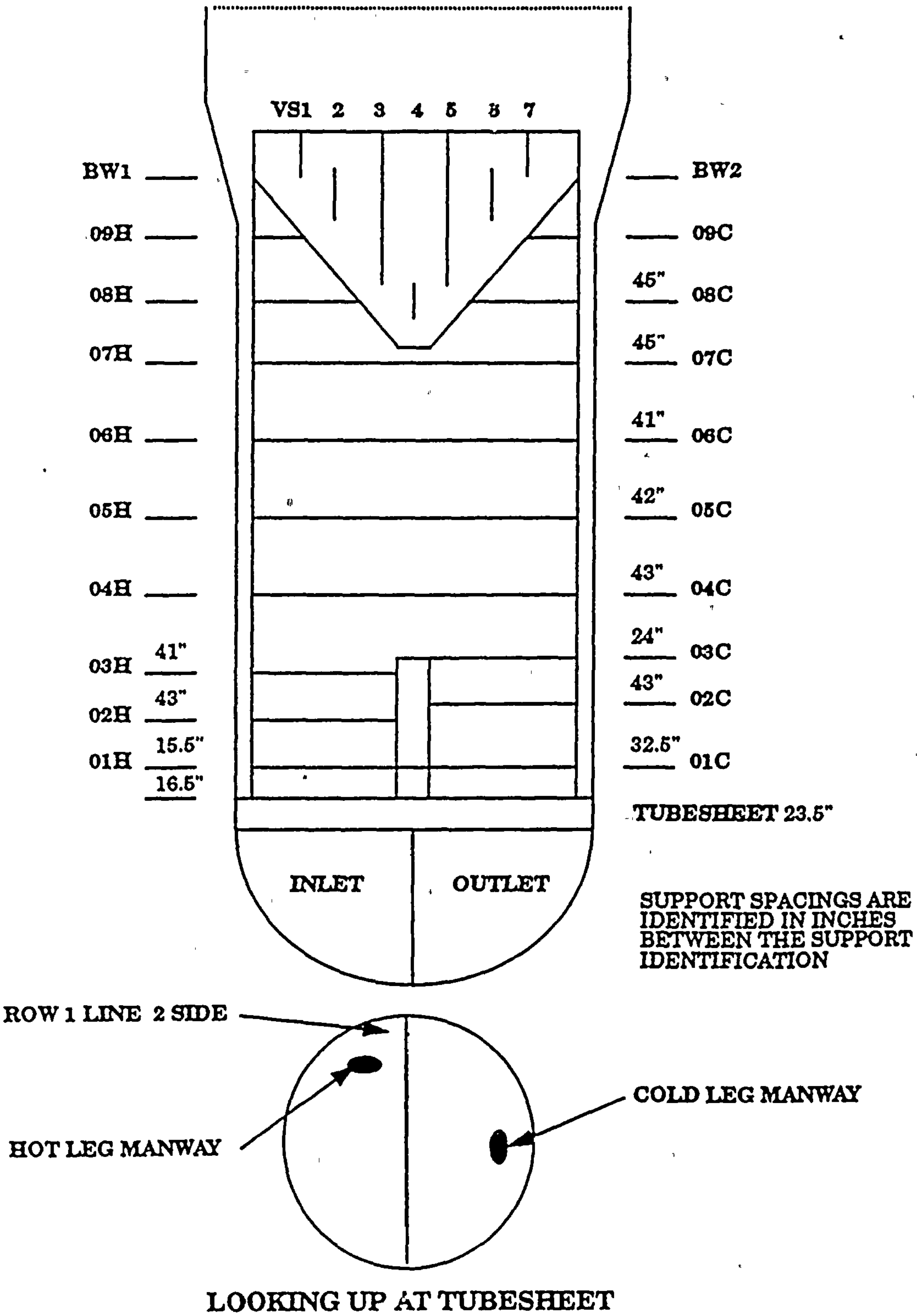
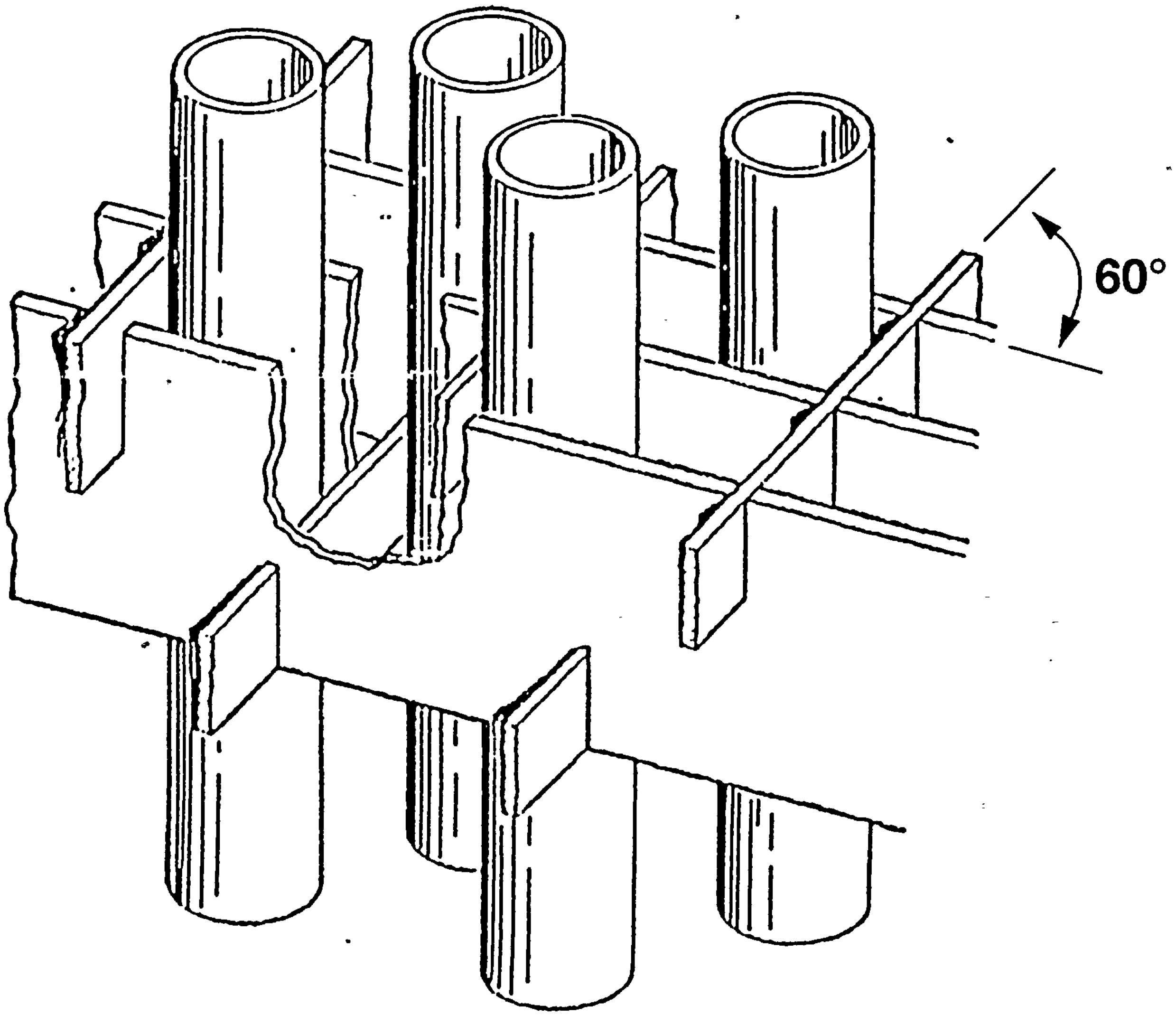


Figure II.C.b

FIGURE II-C.2.a

Steam Generator Eggcrate Tube Supports



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SUPPORT3

FIGURE II.C.2.b

Eggcrate Support Detail

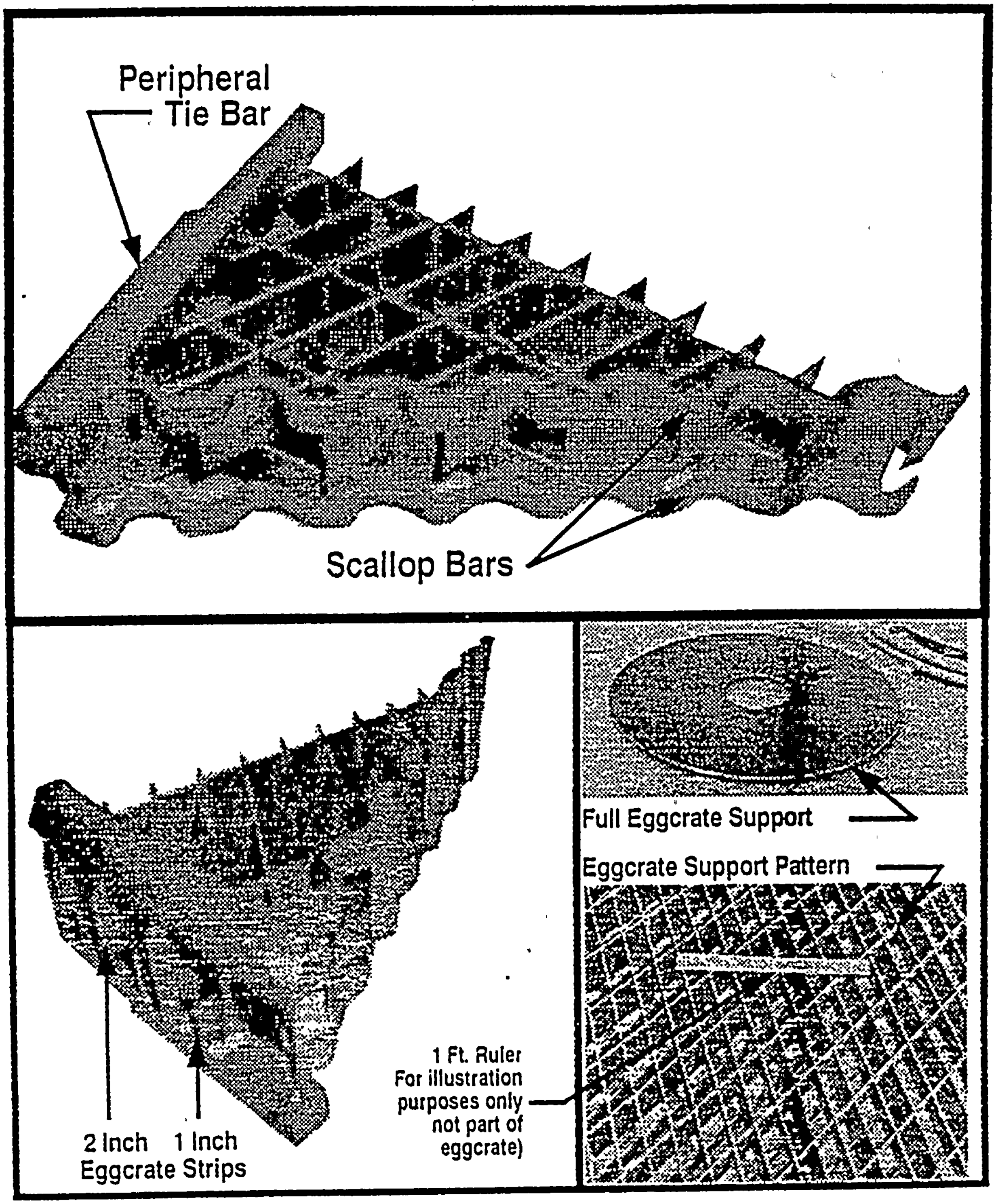
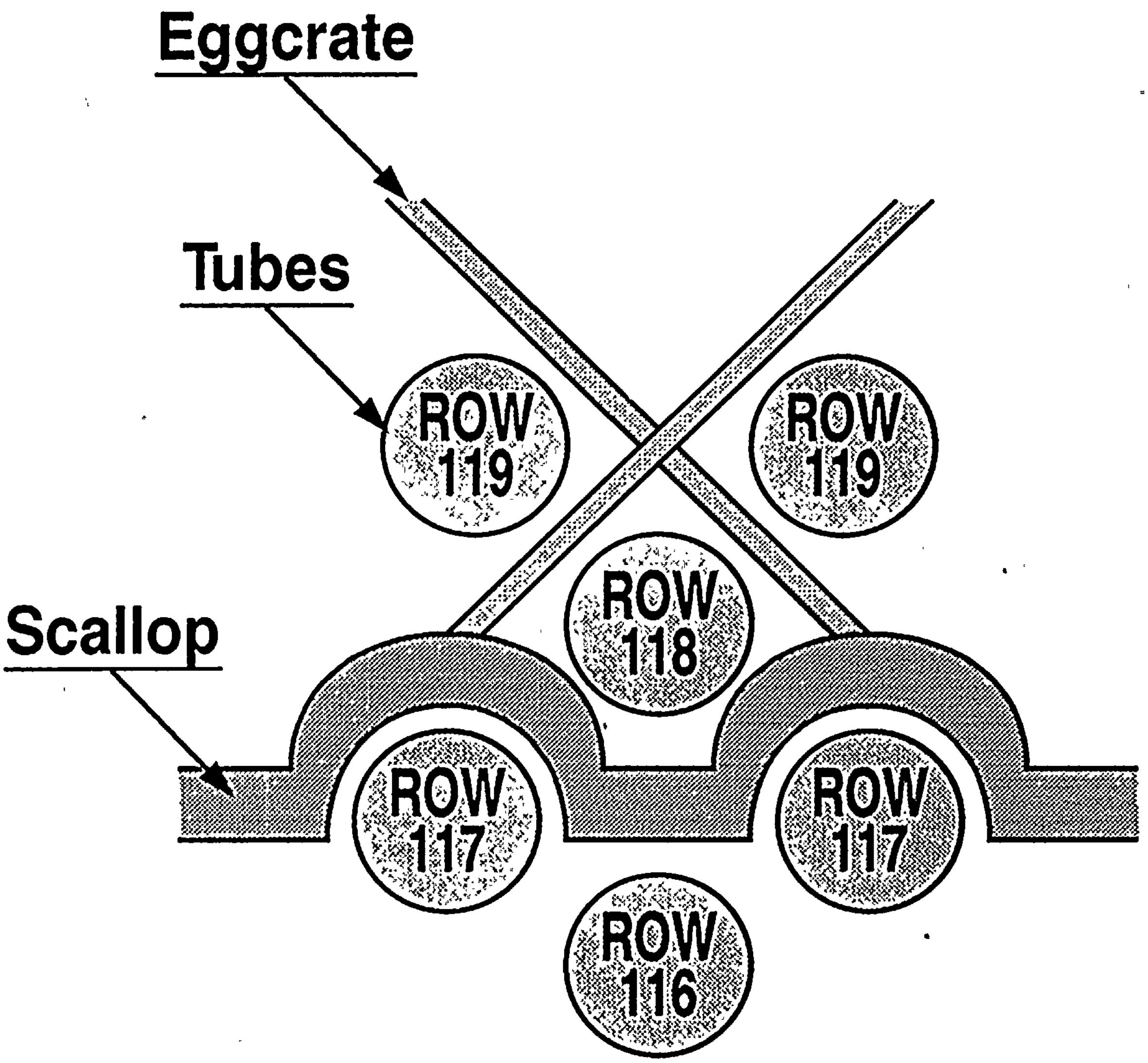


FIGURE II-C.2.c

Partial Eggcrate 09H Scallop Arrangement



NOTE:

Row 117 is not actually in the 09H support. Rather, it rests next to the 09H support edge.

Eggcrate

FIGURE II-C.3.a

Palo Verde Upper Tube Bundle Supports

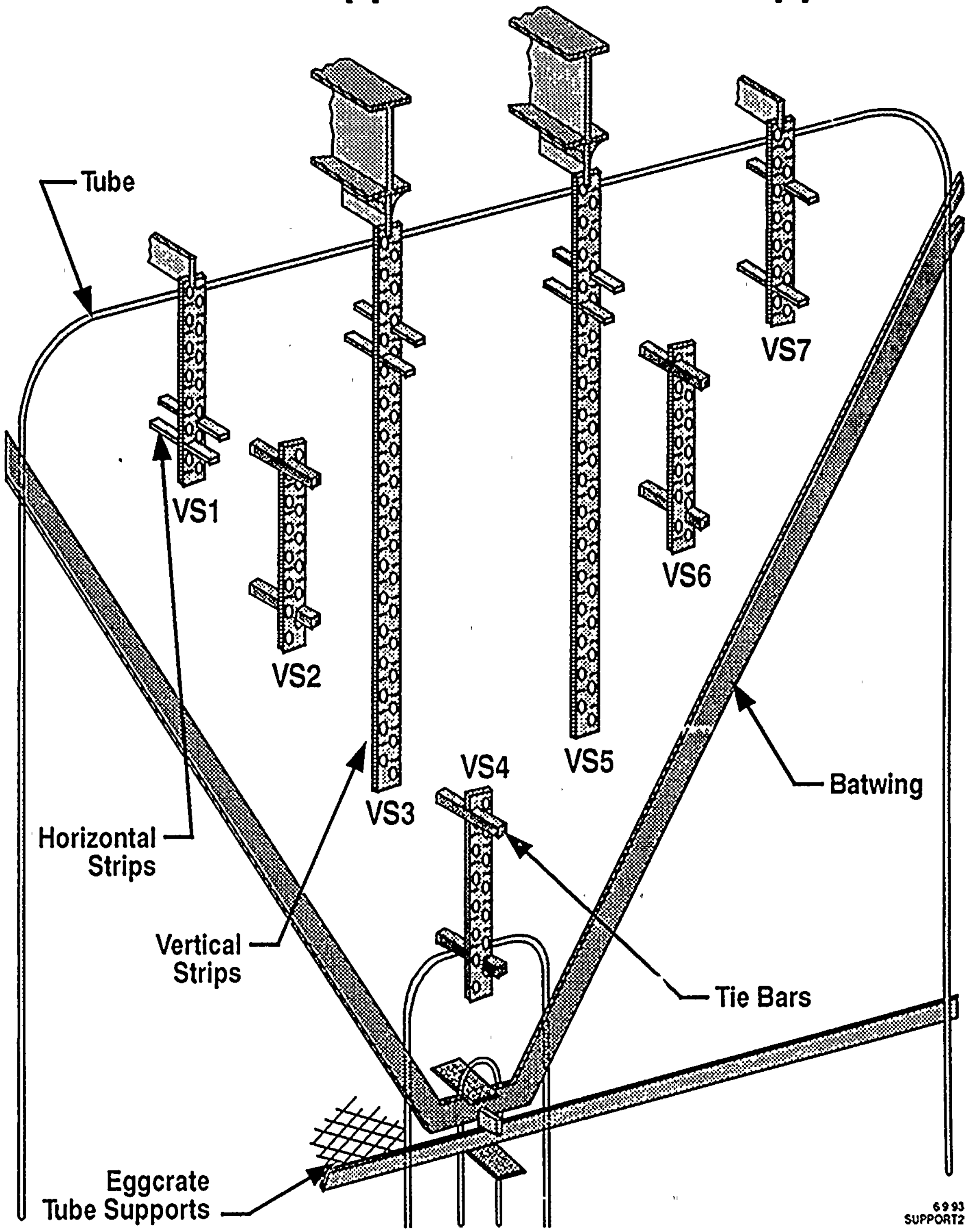


FIGURE II.C.4.a

ABB-CE Ventilated Vertical Tube Support Grid

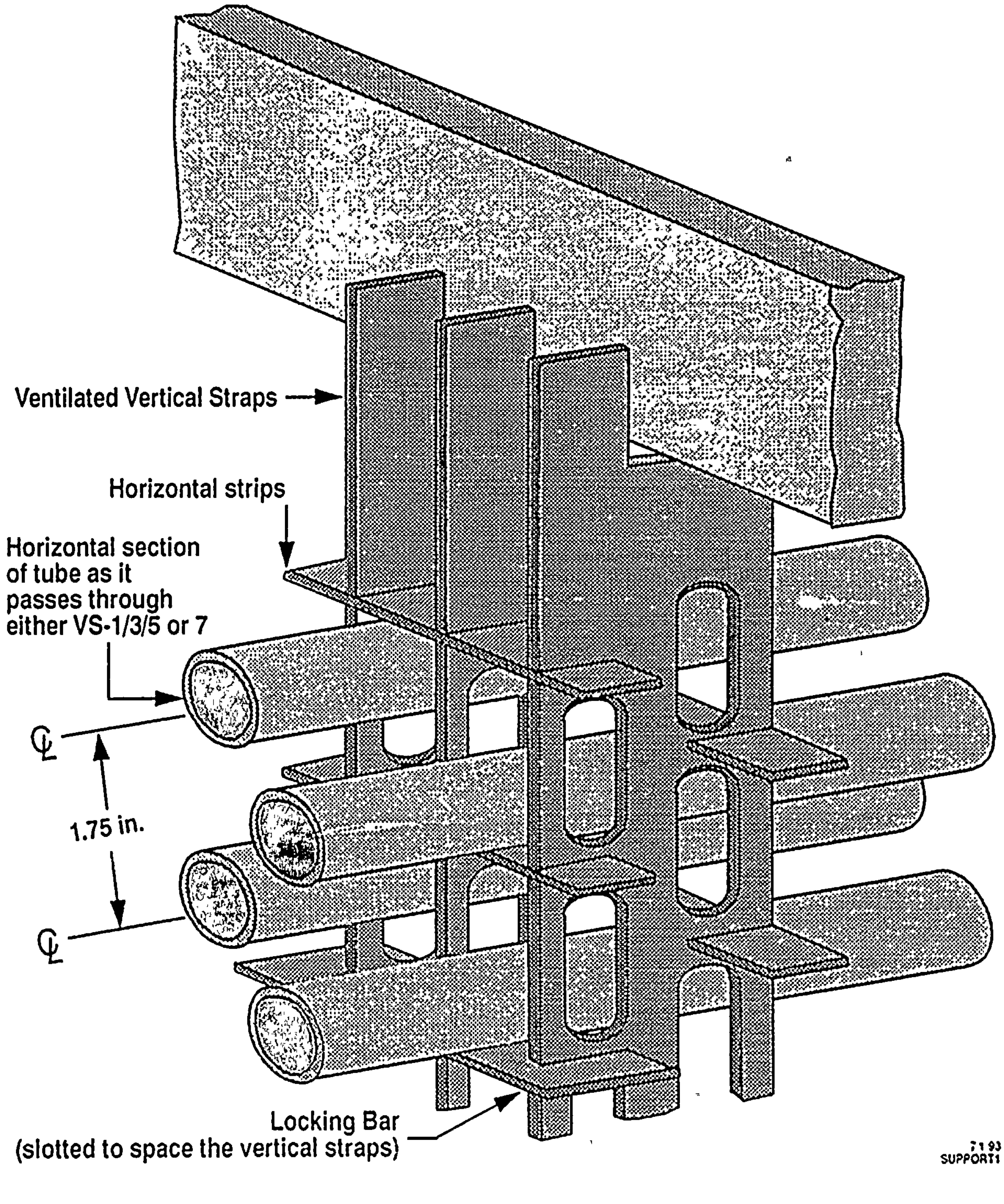
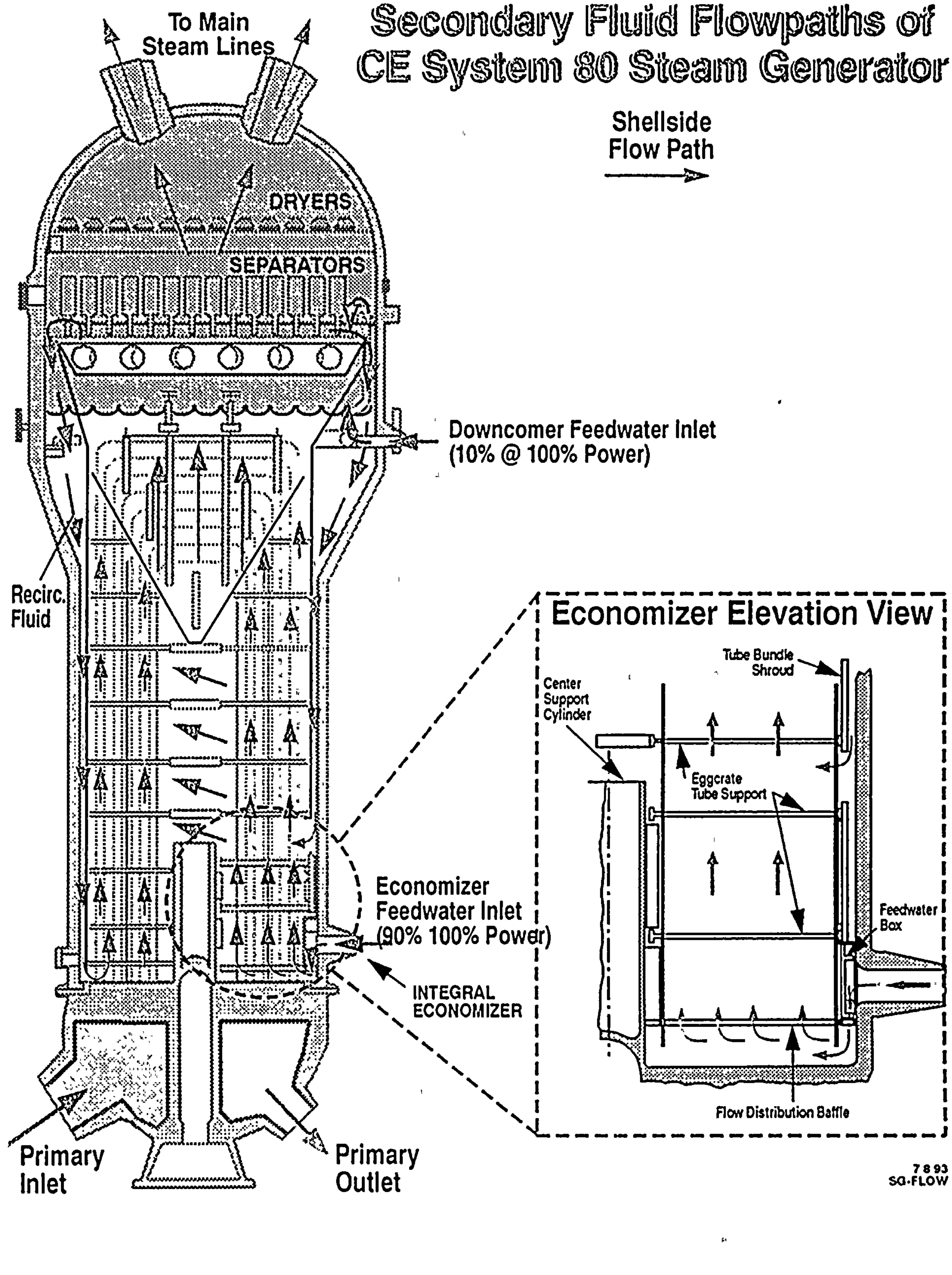


FIGURE II-D.1.a

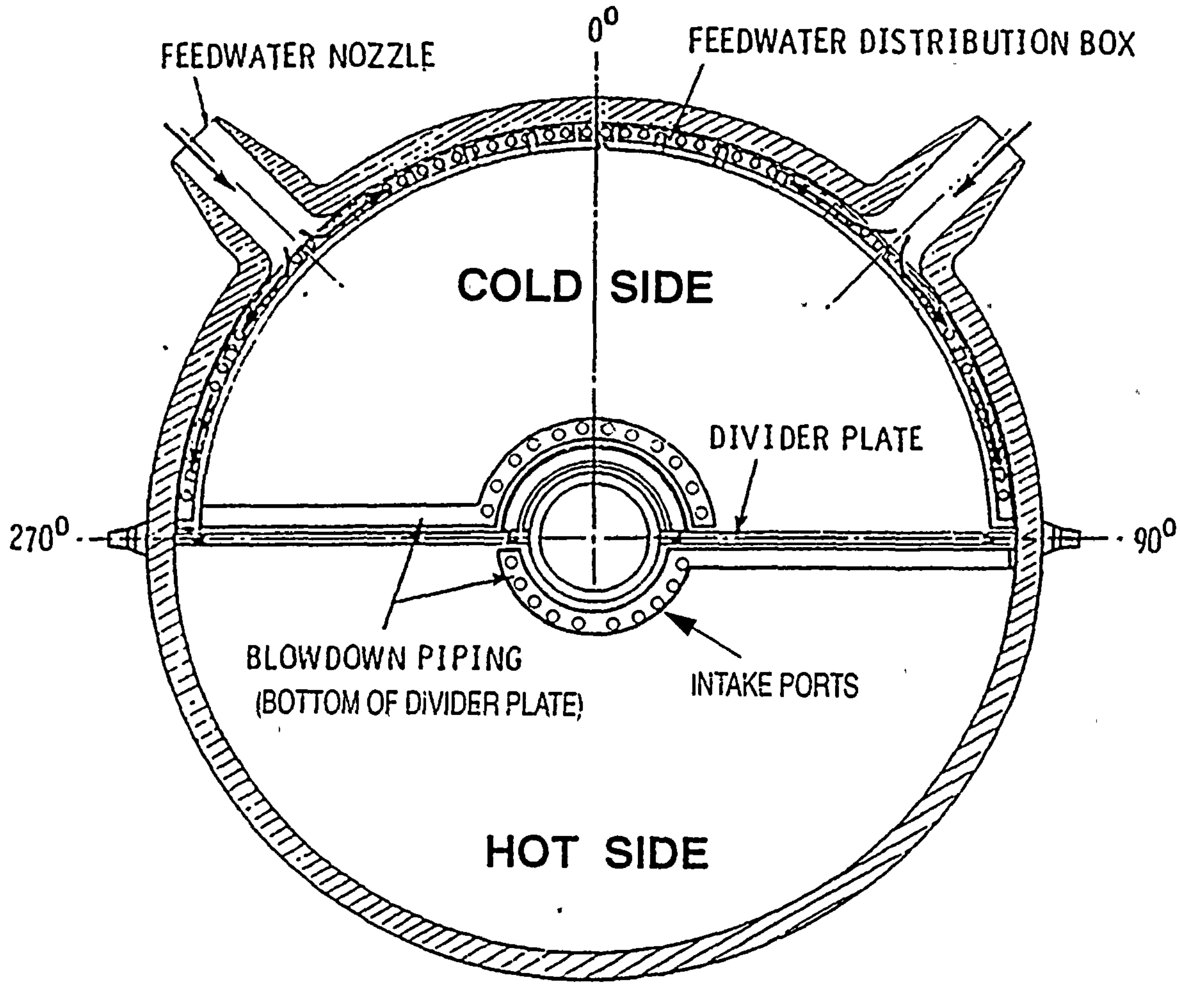
Secondary Fluid Flowpaths of CE System 80 Steam Generator



7 8 93
SG-FLOW

FIGURE II-D.1.b

Schematic Diagram of Blowdown System



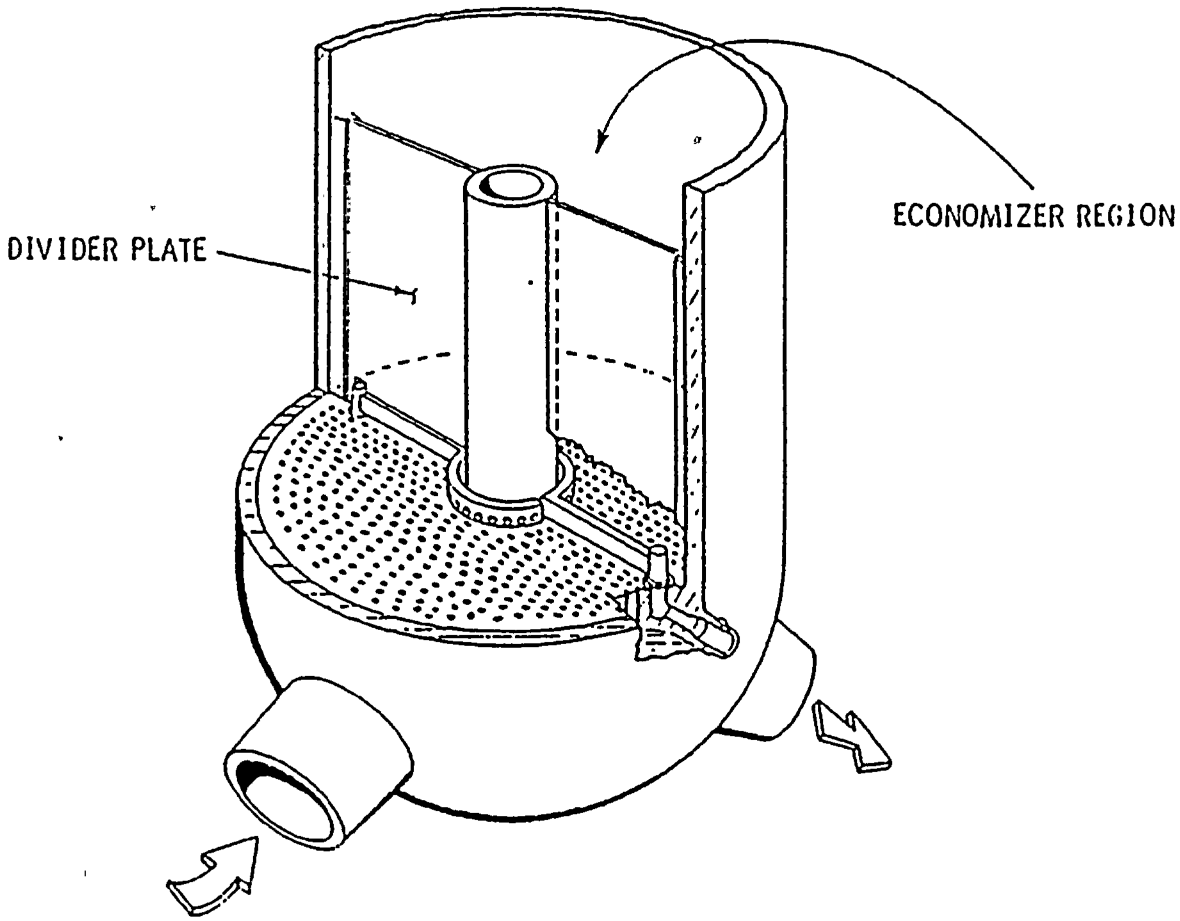
Blowdown Piping Arrangement

6 22 93
BLOWDOWN

FIGURE II-D.2.a

Schematic Diagram of Blowdown System

Economizer Region



6 22 93
ECONO-1

III. INITIATING EVENT AND BACKGROUND

On March 14, 1993, Unit 2 experienced a steam generator tube rupture of approximately 240 gpm in SG 22. Details of the resulting transient and recovery are contained in the Incident Investigation Report for the event (reference IIR-2-3-0012). Unit 2 had been monitoring for primary to secondary leakage since July, 1992. Secondary radiation monitors began to alarm in February, 1993. The alarms were not long in duration but were consistently received during small reactor coolant system pressure transients such as when shifting charging pumps. Beginning March 3, 1993, steam generator I-131 concentrations became large enough to calculate and track leak rate in gallons per day. The leak rate was calculated by the I-131 method at least 19 separate times between March 2 and March 13, 1993. During that time period, the leak rate was nominally 20-30 gallons per day. Increases in leak rate levels were noted during plant changes in power levels and high rate blowdowns. However, the calculated leak rates were decreasing for two days prior to the incident.

IV. FAILURE MODE INVESTIGATION

The purpose of this section is to document the facts associated with the steam generator and facts associated with the failure mode investigations performed. A thorough root cause of failure investigation requires a detailed compilation of the facts related to the component and/or system failure. This compilation or "Facts List" was developed initially to document information that was known about the failure. The list was also used to guide decision making regarding issues that require further investigation and troubleshooting. Additional information or facts obtained during the troubleshooting and/or analysis phases of the investigation were added to the facts list as they were identified/verified. Therefore, the list of factual information regarding the failure did not remain static during the course of the evaluation. The facts assembled for this investigation are stated in this section of the report and are categorized in the following areas:

1. Design of the PVNGS steam generators.
2. The fabrication process associated with the PVNGS steam generators, including the internals of the generator.
3. A detailed review and historical account of the PVNGS Unit 2 steam generator chemistry.
4. Operational review of the Unit 2 steam generators as compared to Units 1 and 3.
5. A detailed review and historical account of the PVNGS Unit 2 steam generator eddy current testing.
6. Deposit formations, chemical analysis and detection methods.
7. Tube examinations on the Unit 2 steam generators during the 2R4 refueling outage.

Specific diagnostic tools were used to help the root cause of failure team develop a comprehensive list of potential failure modes. The following is a list of diagnostic tools used to obtain data for the RCF.

1. Eddy current testing expanded scope during the U2R4 refueling outage.
2. The ECT methodology used to identify and define SG tube degradation.
3. Analysis of pulled tubes.
4. Video analysis of the SG secondary side internals.
5. Tube flaw orientation testing and analysis.
6. Analysis of the design and fabrication.
7. Analysis of contact force.
8. Analysis of loose parts.
9. Effect of level oscillation.
10. Tube wear analysis.

11. Analysis of the potential for flow induced vibration.
12. SG tube metallurgical examination.
13. Review of plant operations.
14. Evaluation of secondary chemistry.
15. Visual examination of the secondary side.
16. Analysis of deposits and its formation.
17. Analysis of sludge samples.
18. Study of chemical sources.

These items are described in detail in section V.

A review of all potential failure modes and associated facts and information led the team to the development of the most probable failure modes. From this review and analysis, a SG Tube Rupture Failure Modes chart was constructed.

A. STATEMENT OF FACTS

1. Design

An evaluation of the PVNGS steam generators's design and assembly was performed. The following are the known facts:

The Palo Verde Unit 2 steam generator tube bundle and tube support design was predicated on the twin objectives of: (1) Providing adequate support of the tubes against design loadings including flow induced vibration; while (2) simultaneously promoting adequate secondary side flow by minimizing tube-to-tube support crevices which could be vulnerable to contaminant concentration and corrosion.

The following design related facts apply:

a. Palo Verde Unit 2 tubing has the following characteristics:

- It was produced by Noranda in Canada with a pilgering process.
- Each steam generator has 11, 012 U-bend tubes which are 0.75 inch OD and has an average 0.042 inch wall thickness and has an average length of 57.75'.
- The tube material is Inconel 600 high temperature annealed SB-163, with an upper limit of 55 ksi at room temperature yield strength and lower limit of 32 ksi at room temperature yield strength.

IV. FAILURE MODE INVESTIGATION (CONT.)

A. STATEMENT OF FACTS (cont.)

1. Design (cont.)

b. The steam generator parameters are as follows:

- Primary T_{hot} = 621.2°F.
- Primary T_{cold} = 564.5°F.
- Steam pressure = 1070 PSIA @ 100% PWR.

c. The 08H and 09H tube supports are partial eggcrate supports. Tube row 117 is the lowest row number not fully captured by the 09H support, and tube row 66 is the lowest row number not fully captured by the 08H support. (See Figures II.C.a, II.C.2.b, and II.C.2.c.)

d. The Palo Verde steam generators are inverted U-bend heat exchangers with integral economizer on the lower cold leg.

e. The Palo Verde steam generators, which were designed and built by CE, are currently the only operating units of this design (i.e., System 80).

f. The flow distribution plates on both the hot and cold side are designed to promote cross flow to sweep deposits from the tubesheet. They may also function as tube supports but are not required for that purpose.

g. The tube supports are made of 409 ferritic stainless steel material.

h. The hot and cold side flow distribution plates are made from 405 ferritic stainless steel material.

i. Flow distribution plate holes are designed for flow distribution purposes.

j. Tubes vary in length from 550 inches to 985 inches.

k. Orifices are located at the extreme hot side moisture separators for flow distribution and moisture separation performance (62 units).

l. The U-bend tube upper support design (segmented type) for Palo Verde is similar to that of St. Lucie 2, San Onofre Units 2 and 3, and Waterford. Subsequent units (Korea) were designed with a unitized construction so as to incorporate the best features of the ventilated corrosion resistant design with the unitized design to eliminate batwing vibration (SONGS batwing wear problem),

IV. FAILURE MODE INVESTIGATION (CONT.)

A. STATEMENT OF FACTS (cont.)

1. Design (cont.)

m. The scalloped bars on the 08H and 09H tube supports are made of carbon steel material.

n. Cross flow was anticipated in the upper regions of the tube bundle, and the tube supports were designed accordingly.

o. Flow velocities in the generator were designed to be 76% of Connors critical velocity for the threshold of fluid elastic instability.

p. The design in the region of the partial eggcrate scalloped bars provides:

- Row 117 tubes have a 0.016 inch design radial clearance as assembled with the scallop bar.
- Row 116 would be 1/8 inch from the scallop bar.
- Row 118 tubes have a 0.016 inches design radial clearance as assembled with the inside of the scalloped bar.
- Row 119 falls within the 09H eggcrate.

q. Generators with batwings (BW) and vertical supports (VS) similar to CE System 80 experienced more wear at the vertical supports than earlier units but have experienced less corrosion damage.

r. Design changes for Korean plants were to preclude the PVNGS corner wear problem and to eliminate the BW wear near the central cavity (SONGS BW wear problem). Other changes included the removal of the distribution plate (O/H) on the hot leg side, thus increasing the circulation ratio from 3.0 to 3.9, at normal full power.

s. Initial maximum design calculation for steam flow using CALYPSO model was predicted to be ≈11 ft/sec and was later evaluated to be ≈31 ft/sec → using Analysis of the Thermal-Hydraulics of Steam Generators (ATHOS) model.

A. STATEMENT OF FACTS (cont.)

2. Fabrication

A review of the fabrication process for PVNGS's steam generators was performed, and the facts pertinent to the process are provided below. The steam generator tubing operation was performed in an atmospherically controlled "clean" room at CE's Chattanooga, TN facility. The process consisted of the following steps: installation and optical alignment of the flow distribution plates and "eggcrate" tube support grids with tubesheet drilling pattern; insertion of tubes on a row by row basis with a gradual assembly of the vertical support grids as tube rows were inserted; placement, sizing and tube-to-tube sheet welding of tubes as they were inserted; installation of batwing wrapper bars, vertical grid "crescent" plates, and tube support beams; and explosive expansion ("explansion") of tubes within the tubesheet full depth.

The following fabrication facts apply:

a. U-bend tubes were inserted in the horizontal plane by hand with a four-man tube handling crew such that both hot and cold legs were inserted simultaneously.

b. Pilgered tubing (performed from the OD) has a noticeably higher noise level due to ID surface irregularities inherent within the pilgering process. Most tubing produced since the mid-seventies (including Palo Verde tubing) has employed the pilgering process.

c. Based on CE experience, Palo Verde SG 22 had an average number of factory plugged tubes, but SG 22 had more tubes (28) plugged than the other five PV steam generators. SG 11 = 4 factory plugs, SG 12 = 20, SG 21 = 9, SG 22 = 28, SG 31 = 4 and SG 32 = 20 factory plugs.

3. Chemistry

In investigating the potential failure modes, several chemistry related areas were reviewed and the following list of facts assembled.

a. **Feedwater Flow**

- Feedwater flow rate to SG 21 was 1.15% higher than flow to SG 22 during the previous operational cycle, but is considered to be negligible impact.

IV. FAILURE MODE INVESTIGATION (CONT.)

A. STATEMENT OF FACTS (cont.)

3. Chemistry (cont.)

b. Blowdown Flow Rate

- Unit 2 had longer periods of abnormal rate blowdown than Units 1 and 3.
- Blowdown flow is diluted by feedwater. This makes an already low rate of normal blowdown even more inefficient at removing ionic species.
- SG 21 and SG 22 had equivalent normal rate blowdown flows, based on 8/92 data.
- SG 22 abnormal rate blowdown flow was two times higher than SG 21, based on 8/92 data.
- PV blowdown flow rates (35-50 gpm normal rate) are lower than some other plants (such as SONGS at 150 gpm). This can correspond to higher concentration of ionic impurities in the bulk water.

c. Hideout Return Studies

- The average peak sodium hideout return concentration (1987-1993) was higher from SG 22 than SG 21 (270 versus 172 ppb). The other units did not show that level of variance between their generators.
- The average peak sodium hideout return from SG 22 was higher than the other five SGs (1987-1993).
- The molar ratio calculated from the average hideout return peak concentrations of Na/Cl were higher in SG 22 than SG 21 (19.2 vs. 2.9) (1987-1993).
- The most recent hideout return data (1991-1993) indicates Unit 2 experienced the highest return of sodium and sulfate and the lowest return of chloride when compared to Units 1 and 3.
- MULTEQ pH values were essentially identical in all three units.
- The concentration of lead returned from Unit 2 in October 1991 was higher than the other units (1991-1993 data).
- The concentration of lead returned from both Unit 2 SG's was essentially identical (SG 21 was 18 grams, SG 22 was 20 grams).

IV. FAILURE MODE INVESTIGATION (CONT.)

A. STATEMENT OF FACTS (cont.)

3. Chemistry (cont.)

c. Hideout Return Studies (cont.)

- PV hideout return Na/Cl ratios are significantly higher than many other utilities (refer to SONGS data as a comparison).
- Sulfate hideout return is, however, fairly typical with other utilities.

d. Source Term Study

- The quantity of sulfate from resin fine/bead introduction was not quantified.
- Makeup water and chemical injection were insignificant sources of sulfate.
- Units 2 and 3 demin effluent's sulfate, sodium and chloride quantities were approximately the same.
- PV non-sensitized tubing is not highly susceptible to acid-sulfate or reduced sulfate attack such as are sensitized plants like TMI and Palisades.
- Sulfates do not depress crevice pH as significantly as chlorides do. Elevated sulfate does not necessarily imply acidic crevice conditions.

e. Hideout Return Sulfate

- The average concentrations of sulfate observed (1987-1993) during hideout was within 10% for all three units.
- Generally, the highest concentrations of sulfate have not been seen in prompt hideout return.
- The most recent hideout return data from Units 1 and 3 indicated increased prompt sulfate hideout return.
- The increased prompt sulfate return occurred as the molar ratios were reduced during the past six months (possibly related to decreased use of condensate polishers or changes in crevice pH [i.e., as molar ratio (MR) is reduced, the crevice becomes more acidic the tendency for acidic species to accumulate goes down]).

IV. FAILURE MODE INVESTIGATION (CONT.)

A. STATEMENT OF FACTS (cont.)

3. Chemistry (cont.)

f. Resin Intrusion

- A failure of condensate demineralizer service vessel (SV) "B" occurred in July 1991 in Unit 2. A similar problem occurred during February 1992 due to SV "E" retention screen problems.

- Sulfate concentrations in blowdown samples did not increase following the 1991 event, but sulfate levels did increase in January and February 1992.

- Due to the very high absorption rate for sulfate, increases in blowdown sulfate concentrations would not necessarily be noted. The first downpower following these suspected events, however, did not indicate any increased sulfate hideout return.

- Very small quantities of resin were observed during visual inspections of SG 21 and SG 22 can decks performed during May 1993.

- Tests performed on resin beads obtained during the above-mentioned visual inspection, determined that the resin type could not be determined (anion, cation or inert), but that the cation functional group (sulfonic) was removed.

g. EPRI Tracer Test

- Based upon an Electric Power Research Institute (EPRI) tracer test, the majority of impurities introduced into the SG remained during operation. The following hideout fractions were identified: chloride 70%, sodium 80%, potassium 89%, sulfate and calcium approach 100%. These levels are higher than observed in other utilities which have performed similar tests, approximate factor of two times higher.

h. Sampling Methodology

- Downcomer sample impurity concentrations were approximately a factor of six times higher than hot leg blowdown sample concentrations partially due to dilution of the blowdown sample with feedwater. Prior to 1993, hot leg samples were used to control SG chemistry.

A. STATEMENT OF FACTS (cont.)

3. Chemistry (cont.)

h. Sampling Methodology (cont.)

- A more concentrated and potentially aggressive bulk water environment will be present at the top of the hotleg blowdown side tube bundle. Also the presence of higher levels of impurities can alter or "confuse" key metallographical indicators such as the Ni/Cr ratio (possibly why the 01H looks more caustic than 09H).

- A lithium tracer test was performed in Unit 2's SG's in 1987. The test performer, CE, concluded and recommended the use of the downcomer sample point as the primary sample location for more accurate determination of the SG's chemistry (reference V-CE-34773 dated June 16, 1987).

i. Condenser Leaks

- Based upon an engineering assessment of historical tube leak events, Unit 2 has experienced more condenser tube leaks than the other two units (approximately two times the site average of 1.7 reported leaks per year).

- The number of condenser tube leaks was significantly reduced in 1988 after lathing was installed to stabilize the tubing. Unit 2 continued to experience approximately twice as many tube leaks as the site average of 0.27 reports per year.

- A condenser tube leak in Unit 2 during 1990 was particularly severe at an estimated 150 gpm. (This data point not used in the above averages.)

- With the exception of a condenser tube rupture event which occurred during the Unit 1 warranty run, the condenser tube leaks were contained by the condensate demineralizers.

j. Secondary Chemistry

- All three units have operated in accordance with plant procedures, EPRI, and Combustion Engineering Owners' Group (CEOG) industry guidance.

- All three units have operated with essentially identical chemical control programs since startup (ammonia/hydrazine with full flow condensate polishing).

A. STATEMENT OF FACTS (cont.)

3. Chemistry (cont.)

j. Secondary Chemistry (cont.)

- A series of enhancements were made to all three units' condensate demineralizer operations that resulted in reduced sodium throw.
- Full bypass operations of the condensate demineralizes were initiated in Units 1 and 3 during 1993. Unit 2 required its demineralizers remain in service due to a small condenser tube leak during the last cycle.
- Feedwater pH was increased slightly during 1992 from > 8.8 to > 9.15 to reduce iron transport.
- Feedwater hydrazine was increased from 20 ppb to > 100 ppb in 1992 to reduce the SG's electrochemical potential.
- Molar ratio chemistry control was initiated in 1992 with significant reductions in molar ratio occurring in all three units.
- The generators within a unit operate with different chemistries despite having a common feedwater source. SG 1 in Units 1 and 2 operated with the higher impurity removal; whereas in Unit 3, SG 2 operated with the higher removal.
- Trends in chemistry impurity levels had been consistent with plant operations in all three units.
- The molar ratio trends from all three units indicated chronic alkaline chemistry control patterns.
- Iron transport data estimated that greater than 3 pounds of iron per day could have accumulated in each steam generator. That would equate (theoretically) to over 5,000 pounds to date. Minimal tubesheet fouling had been observed by ECT.

IV. FAILURE MODE INVESTIGATION (CONT.)

A. STATEMENT OF FACTS (cont.)

4. Operational Review

A review of operational practices, issues and activities was performed in order to identify any anomalies or areas that would contribute to the potential failure mode identification. The list of facts assembled from that are as follows:

a. A feedwater oscillation occurred in Unit 2's SG's that did not occur in either Units 1 or 3.

b. As of March 31, 1993, Unit 2 had the highest cumulative thermal generation of the three units.

c. Vibration/loose parts alarms were received in the Unit 2 control room prior to the event.

d. The majority of vibration/loose parts alarms were on the reactor pumps' sensors.

5. Eddy Current Testing

a. The following details indications and information were obtained during U2R3 (1991):

- Axial cracking in SG 22 at 01H.
- Axial cracking in SG 22 at R117C54 at 09H+3.1 inch freespan, at R112C151 at BW1+3.62 inch span, at R134C97 at BW1+3.73 inch freespan.
- Wear at batwings, cold leg corner eggcrates, eggcrate supports, vertical straps.
- Some identified loose parts wear.
- Prior to U2R4, SG 22 had 196 tubes plugged.
- Prior to U2R4, SG 21 had 114 tubes plugged.
- More wear/tubes plugged at BW1, upper eggcrate.
- Decreased number and depth of indications were observed in U2R3 outage as compared to the U2R2 outage.
- 100% of SG 21 and 75% of SG 22 were full length bobbin tested during 1991 outage.
- 100% of the 01H flow distribution plate was inspected using bobbin probe in SG 22 and SG 21.
- 100% of freespan area above 09H in SG 22 was inspected using bobbin probe due to R117C54 indication.

IV. FAILURE MODE INVESTIGATION (CONT.)

A. STATEMENT OF FACTS (cont.)

5. Eddy Current Testing (cont.)

b. Information and data obtained from ECT during U2R4 is provided below:

- SG 22 had more wear indications than SG 21.
- Axial cracking was found in the freespan and the upper bundle supports.
- Deposits (characterized by using low frequency channels) were noted on freespan locations.
- Single volumetric indication (SVI) were identified this outage but not characterized.
- MRPC inspection summary (Tables V.A.1 and V.A.2).
- Two previous PLP indications found during the 1991 outage have been reclassified as axial indications based on 1993 ECT findings.
- All freespan indications and majority of support axial indications were found inside an arc as depicted in Figures V.A.4 and V.A.5.
- Axial indications were noted to be exclusively in the hot leg side and predominantly on vertical runs.
- One axial indication was located at tube R131, C46 at BW1 + 19 inch (i.e., horizontal run) in SG 21.
- A number of freespan axial indications are associated with linear deposits (found with low frequency motorized rotating pancake coil [MRPC]).
- The bobbin coil can not detect the presence of linear deposits using current methods and equipment.
- Eighty-one (81) (SG 22) and 16 (SG 21) indications identified by MRPC were not previously called during analysis of bobbin coil data.
- An increased number of wear indications was found at 08H, 09H, BW1 (i.e., upper regions of the hot leg).
- See Tables V.A.5 and V.A.6 for summary of axial indication.

IV. FAILURE MODE INVESTIGATION (CONT.)

A. STATEMENT OF FACTS (cont.)

6. Deposits

- Deposit indications were detectable during ECT by MRPC, but not by bobbin probe.
- Limited MRPC inspections at elevations below the 07H identified a very small quantity of mid-span deposits, primarily located between the tubesheet secondary face and 01H.
- Many axial mid-span indications had a corresponding deposit indication, although there were many deposit indications without identified axial flaws.
- Secondary side video inspections in SG 22 showed deposit bridging across a narrower-than-normal gap between the following tubes at the same height as the flaw:

  117-40 and 115-40 (both tubes had axial cracks.)
  117-42 and 115-42 (both tubes had axial cracks.)
  103-156 and 102-155 (only 103-156 had an axial crack.)
  115-144 and 117-144 (both tubes had axial cracks.)
  104-157 and 105-156 (both tubes had axial cracks.)

- Using eddy current identification of deposits, numerous sets of adjacent tubes with deposits at overlapping heights were found in both SG's 21 and 22.
- ECT measured length of deposits varied over the entire range of the mid span, but the median was ≈8 inches in length the mean was ≈10 inches in length.
- Visual inspection of 116-41 in the lab identified a deposit ≈3/8 inch wide, 2 mils thick, axially oriented.
- Laboratory analysis of chemical contaminants in deposits showed greater concentrations at progressively increasing heights in the pulled tubes.

7. Tube Examinations

A number of facts were identified and assembled base on the results of the pulled tube examinations and are presented below:

- Defects were OD initiated IGA and IGSCC (no transgranular cracking). The cracks were axial and often multiple.

A. STATEMENT OF FACTS (cont.)

7. Tube Examinations (cont.)

- Cracking is a combination of IGA and IGSCC, with the trend towards IGSCC as the crack propagates throughwall.
- Mid-span crack indications tend to be long (>10 inches).
- OD surface, midcrack and crack tip oxide elemental and compositional analysis have shown the crack crevice chemistry to be alkaline.
- Oxide chemical analysis also indicated the presence of Pb, SO_4^{2-}, S^{2-}, Mn, Mg, Cu and Si.
- Freespan defects (i.e., near throughwall and throughwall) are associated with linear, ridge-like deposit formation in the upper tube sections.
- Freespan defects on R105C156 (i.e., near throughwall and throughwall) are also associated with worn surface areas which have numerous axial oriented scratches within these areas.
- Tube IGA/IGSCC was identified in areas without significant worn areas with scratches, however, the extent of the attack was not as severe as the worn areas.
- Tube material sensitization testing (grain boundary chromium carbide formation) displayed a low degree of sensitization.
- Tube bulk chemistry data for samples received to date meet specification requirements.
- Crevice chemistry environment is alkaline with sulfates based on auger electron spectroscopy/X-ray photoelectron spectroscopy (AES/XPS) analysis.
- Lead not considered to be a major factor (low levels of 0.3 to 0.5 wt.% detected).
- No evidence of acidic attack (pitting/wastage).
- Wear contact is shallow and oxidized, indicating older, past contact versus active contact.
- No ridge deposits at eggcrate support.
- Degradation is IGA/IGSCC with significant IGA component (no transgranular cracking).
- Worst case cracking as seen in tube 105-156 associated thick deposits with surface scratched areas which could accelerate degradation due to cold work.

IV. FAILURE MODE INVESTIGATION (CONT.)

A. STATEMENT OF FACTS (cont.)

7. Tube Examinations (cont.)

- Thick ($\geq$4 mils) deposits sufficient to cause IGA/IGSCC without scratched areas (cold work).
- Tube R117C144 found to have slight intergranular carbides and no intragranular carbides resulting in reduced IGSCC resistance in alkaline environment (not typical of HMA tubing).
- Tubes R105C156 and R103C156 also found to have microstructures not indicative of HMA.
- IGSCC present on tube OD within crevice regions formed by 01H flow distribution baffle plates.
- Copper, chromium and lead concentrations significantly lower at 01H locations compared to freespan location.
- Crack crevice at 01H and tube sheet determined by AES/XPS results to be caustic based on chromium depletion and nickel enrichment.
- Material microstructure acceptable for R22C13 and R29C24.

B. FAILURE MODE REVIEW

The focus of this Root Cause of Failure investigation was to determine the cause(s) for the fish-mouthed axial cracking which occurred in SG 22, tube R117C144. Based on early eddy current testing and video evidence, the tube failure was determined to be the result of outside diameter initiated axial cracking. Based on the facts and information available early in the investigation, the Steam Generator Tube Rupture Task Force developed a flow chart identifying possible failure modes (see Figure IV.B.a, SGTR Event Failure Modes). Based on the initial findings, APS identified four possible failures modes:

Outside Diameter Stress Corrosion Cracking (ODSCC)

High Applied Stress

Flow Induced Vibration

Loose Parts

Each mode can act independently or in concert with one another to cause a tube failure.

Based on further review of these failure modes, possible contributing factors (CF) were also identified on the flow chart. Utilizing the SGTR Event Failure Modes flow chart as the starting point in the investigation, the Task Force developed action plans to obtain evidence that would support or refute the possible failure modes. The action plans included a review of SG operating history, analytical studies, SG inspections, and metallurgical evaluation of pulled tubes. Subsequent sections of this report provided the details of these efforts and the results to date. A brief discussion of the possible failure modes is provided below.

ODSCC

When Stress Corrosion Cracking (SCC) is initiated from the outside diameter or secondary side of the SG, it is termed ODSCC. Industry experience indicated this mechanism of SG tube failure was likely in Palo Verde's case and has been observed in many other pressurized water reactor plants that use Alloy 600 SG tubes. The cause of ODSCC is not limited to a single factor but rather is a combination of various forms and magnitudes of three factors (see Figure IV.B.d): material type, stress in the material and environment the material is subjected to.

B. FAILURE MODE REVIEW (cont.)

1. Material Type

Metallurgical analysis was used to evaluate three material properties to determine their potential contributions to the tube rupture. The properties evaluated were microstructure, material composition and heat treatment. The material composition of the tubes was confirmed to be Inconel 600. The microstructure analysis identified some inconsistencies in the tube metal. Differences found were in the metal grain boundaries, grain size and the amount of carbides. Details of the metallurgical analysis and results are provided in Section V of this report.

The heat treatment process applied to the tubes could affect the resistance to intergranular attack and SCC. To obtain the specified yield strength, the tubes were conditioned through a high temperature mill annealing process. To verify the acceptability of the heat treatment, documents (CMTR) were reviewed to ensure all tubes were within the design specification (yield strength greater than 32 ksi but less than 55 ksi). The review of the CMTR documents was inconclusive in identifying a correlation between the heat treatment lots and the flawed tubes. However, some metallurgical evidence suggests that the heat treatment may not have been adequate to obtain the most optimum tube condition, but the yield strength of the tubes examined were acceptable.

2. Stress

Stress is another factor required for SCC to occur. Several sources of stress were evaluated to determine the contribution of stress in the axial cracking. There are basically two types of stresses associated with axial cracks. They are applied stress, which can be either constant or cyclic, and residual stress.

The applied (constant load) stresses evaluated were hoop stress, stresses from bowing, thermal expansion, and support misalignment. The cyclic applied stresses evaluated were vibration, pressure, thermal and two-phase flow induced vibration.

Hoop stress resulting from the pressure differential between the RCS pressure (inside tube) and the secondary pressure (outside tube) is approximately 1200 psi. This is equivalent to a stress of about 10 to 12 ksi (thousand pounds per square inch) axially. The evaluation of bowing, thermal expansion and support misalignment concluded stresses resulting from these types of conditions generally create circumferential stresses and very little axial stress.

The contribution of stress generated from vibration could not be measured; however, the presence of vibration is apparent due to the excessive amount of wear identified in the Unit 2 SG's.

B. FAILURE MODE REVIEW (cont.)

2. Stress (cont.)

Although the pressure cycling can create an axial stress, it was determined that the maximum pressure swings were approximately 50 psi. Therefore, since the normal pressure difference is approximately 1200 psi, the effect of the 50 psi pressure swings is considered to be negligible.

The stress associated with thermal cycling was another potential source that was evaluated. Thermal stress results from the differential temperature across the tube wall. The difference in temperature varies as the tube is surrounded alternatively by saturated water, two phase mixtures and steam blanket. Based on assumed thermal cycling conditions, the maximum stress is estimated to be approximately 3 to 5 ksi axially.

Flow induced vibration (FIV) has been analytically determined to be a possible failure contributor, most likely in a form of a high cycle, low impact, Hertzian contact stress. Additionally, the FIV could also be a contributor to the axial cold work sights as well as tube wear.

Residual stresses can also be a contributor to the axial cracks. Long freespan scratches were observed on some of the pulled tubes. These scratches could result in local areas of high residual stress or an area of cold working which could increase the tube's susceptibility to SCC. It should be noted that not all scratches or groves resulted in areas of high residual stress or cold work.

3. Environment

Inconel 600 steam generator tube material is susceptible to ODSCC. A significant factor in the development of SCC is the environment to which the material is exposed. The rate and severity of SCC can be influenced by the presence and concentration of contaminants. The presence of crevices or deposits can result in localized areas of concentrated chemicals or a more severe pH.

Chemical contaminants in the SG's are controlled by maintaining the bulk chemistry of secondary systems within plant chemistry specifications. Based on the bulk chemistry of the water within the SG, a prediction of the conditions within crevices and deposits can be derived using computer analysis. A historical review of Unit 2 plant chemistry data was conducted. The review included a comparison of Unit 2 chemistry with that of the other PVNGS Units. Chemical analysis of deposits on the tubes and spectrometry of crack surfaces provided insight into the type and concentration of chemicals within the steam generators. The areas evaluated were bulk chemistry, crevice chemistry, deposit formation, temperature, and time. Evaluation of the bulk chemistry indicated that the Unit 2 chemistry was consistent with Unit 1 and 3, and that prior to 1993 the molar ratio trends for all three units indicated a chronic caustic chemistry control pattern.

B. FAILURE MODE REVIEW (cont.)

3. Environment (cont.)

Crevice chemistry can be best determined utilizing MULTEQ. MULTEQ analysis has predicted a highly alkaline to caustic crevice condition. Unit 2 has also recorded the highest levels of sodium and sulfate return.

Mid-span deposit formation was unique to Unit 2 and analysis concluded that the deposits in the upper region of the SG had a chemical composition several times greater than that found in the lower region.

The rate of SCC for a given chemical environment is also influenced by temperature and time. The pressurized water reactors at PVNGS operate with a reactor coolant system temperature that is higher than most plants. Hot leg temperature at normal is 621°F. Also, Unit 2 was found to have more operating time at 100% power with less down powers during the last operating cycle. Although these two factors contribute to the tube failure, they can not be quantified.

High Applied Stress

SG 22 had a history of high tube wear prior to the tube rupture. One of the possible causes for the wear was high contact forces at the point of contact with the tube supports. This possibility had been discussed with CE and a secondary side entry had been made in the previous outage to look for evidence of this condition. When deposits were noted at the upper areas of the hot leg side of the tube bundle, a possible scenario developed. The scenario was that high stresses were applied to one or more tubes during temperature changes due to deposit induced lock up of the tubes. The tubes were postulated to be restrained from movement during heat up and cool down. Significant stress could be applied to the tubes in this manner.

A known condition that can generate high applied stress is water hammer in mixed phase systems. The possibility that water hammer was involved in the tube rupture was eliminated early. Tube visual examinations, event reviews and the examinations of pulled tubes did not provide any evidence for this failure mode.

B. FAILURE MODE REVIEW (cont.)

Flow Induced Vibration

In the early phase of ECT, the area where defects were being found appeared to correlate to a region of the steam generator where high velocity two phase flow was expected. Degradation did not start in the region where classical ODSCC was normally found. Based on past industry experience, cracking caused by ODSCC would be expected at lower tubesheet initially, then gradually move up the support structure as the generator aged. This was attributed to temperature effects and deposit locations of the typical recirculating steam generator. It was postulated that abnormal vibration was a possible failure mode either initiating or accelerating cracking in that upper bundle region. To evaluate this possibility, an analysis of the potential for abnormal vibration in the SG was performed. In addition, metallurgical examination for evidence of vibration or cyclic fatigue was performed. The results of the evaluations were also utilized in evaluation of flow induced vibration, not as a primary failure mode but as a contributor to the stress component of ODSCC.

Loose Parts

The video inspection from the inside of the ruptured tube did not reveal the presence of a foreign object on the outside of the tube which could have caused wear and subsequent rupture of the tube. In addition, video inspection of the annulus after removal of the ruptured tube did not reveal any indication of loose parts in the rupture area. The rupture was observed to be a long, jagged edge, axially oriented fishmouth defect. This morphology was not consistent with that expected from a loose parts induced tube rupture. Due to the evidence from the ECT and tube examination, loose parts as a contributor was eliminated early in the investigation.

Root Cause of Failure Work Sheet

As evidence was obtained, the Task Force updated the investigation plan to incorporate supporting or refuting information related to failure mode classification. To track these activities, the original flow chart was expanded (see Figure IV.B.b) to document causal factors and/or pertinent facts. From the expanded flow chart evolved the Root Cause Worksheet (see Figure IV.B.c) which identified the most probable causal factors and provided the Task Force with a summarization of the information gathered to date. The worksheet listed the following items as the most probable causal factors:

- Caustic[1] environment with possible aggravators
- Freespan crevice formation (ridge deposits)

1. The term "Caustic" refers to an overall crevice environment condition. Both the laboratory and MULTEQ analysis indicates an alkaline (pH <10) to caustic (pH >10) environment.

B. FAILURE MODE REVIEW (cont.)

Root Cause of Failure Work Sheet (cont.)

- Contaminant concentration in ridge and support deposits
- Flow induced vibration (cold work and stress)
- Surface residual stresses (cold working and scratches)
- Tube manufacturing (microstructure less than acceptable)
- ECT detectability issues.

The Root Cause Worksheet became the working tool for the Task Force to tabulate information pertaining to the causal factors which include supporting and refuting evidence, possible causes, potential future confirmation and potential corrective actions.

Based on the evidence identified and developed by the Task Force, a most probable failure mechanism was determined. A discussion, including the basis for conclusion regarding probable root cause, is described in detail in Section VI of this report.

Investigation of this possibility included a study by the vendor to evaluate the stresses and effects of such a condition, steam generator entry to inspect for the condition, and examination of pulled tube for overload failure.

C. INDUSTRY REVIEW

A search of Industry Events on INPO's Nuclear Network was performed to identify steam generator problems reported at other nuclear power stations. The areas of steam generator corrosion, wear, defects, and ruptures were investigated to identify events that were similar to the tube failure that occurred at PVNGS. None of the events identified were identical; however, some of them were similar and provided useful information that aided in the analysis of the PVNGS tube failure. The following is a summary of the plant events that were identified and evaluated.

1. McGuire Units 1 and 2 - (Westinghouse)

McGuire Unit 1 was shut down in March 1989, when a tube rupture occurred in their Westinghouse Model D2 steam generator. The tube was removed and metallurgically examined. A 3-inch long axial crack was found below the first tube support on the cold leg side. The crack growth rate was determined.

A second leak occurred in McGuire Unit 1 in January, 1992. Review of the ECT data revealed that the indication had been missed due to another tube failure during the previous inspection. Other indications were also found which were missed during the previous inspection. A high crack growth rate was determined.

Three tubes were pulled from McGuire Unit 2 during the 1992 refueling outage. Long axial grooves and 62% to 73% depth defects were found in the pulled tubes. The McGuire evaluation concluded that the cracks were caused by IGA/SCC and were OD initiated. It was also concluded that cracks associated with grooves, dents, and gouges in the tube material were normal. No adverse chemistry factors were found during McGuire's metallurgical analysis. By using pulled tubes and bobbin eddy current "blind" tests, a 100% crack detectability for cracks that were 50% or greater through wall was achieved.

On May 11, 1992 McGuire Unit 1 detected a 235 gpd leak. The source of leakage was a one inch crack with a pinhole located five inches above the first support plate. The crack was determined to be initiated by a manufacturer's burnishing mark and propagated by stress corrosion cracking. A 60% through wall crack one inch long, five inches above the twentieth support plate was also located during the investigation. As a result of the inspection, 182 tubes were removed from service by plugging. However, few tubes contained indications of freespan "cracks." A majority of the indications were characterized as dents or dings. Six tubes were removed for metallurgical examination. Examination of the removed tubes revealed two types of outer diameter (OD) initiated axial cracking, occurring in the tube freespan region of the pre-heaters. Both types of degradation were associated with mechanical deformation of the tube surface.

C. INDUSTRY REVIEW (cont.)

1. McGuire Units 1 and 2 - (Westinghouse) (cont.)

As of June 1992, 16 tubes had been removed from service at McGuire Unit 2 due to freespan crack-like indications. High residual stresses that exist in the groove regions may have confused the eddy current testing results. Duke Power prepared a Regulatory Guide 1.121 analysis and determined a crack growth rate. Based on this growth rate they determined that the unit could run for 12.2 months without exceeding Regulatory Guide 1.121 limits.

2. Maine Yankee Atomic Power Station (CE)

Maine Yankee was shut down on December 14, 1990 when a 1.4 gpm primary to secondary leak was detected. The leak was identified in the SG 21 on December 12, and gradually increased from .0006 gpm to 1.4 gpm when the shutdown was performed. The source of the leak was determined to be a 2-inch long axial crack at the apex of the U-bend in the steam generator tube. This location was described as a "steam blanket region" where the batwing supports restricted flow, permitting a steam void to form and contaminants to be deposited on the tube surface.

3. Arkansas Nuclear One (ANO) Unit 2 (CE)

ANO Unit 2 was shutdown on March 9, 1992 when a .25 GPM primary to secondary leak was detected. ECT inspection of the steam generator tubes was conducted using an MRPC probe. The ECT inspection results identified the source of the leak as a circumferential crack in a tube at the hot leg expansion transition, near the top of the tubesheet.

Based on the finding of the circumferential crack, a 100% MRPC inspection was conducted of the expansion transition locations on the hot leg side of both SG's. A 20% MRPC inspection of the expansion transition on the cold leg side of one SG was also conducted. Indications (generally circumferential) were found on the hot leg side of 488 tubes. No indications were found on the cold leg side. Tubes with MRPC indications were also inspected with a bobbin probe, however, that probe did not detect most of the MRPC indications. Three tubes were pulled for analysis. The analysis determined that the circumferential cracking was caused by intergranular stress corrosion cracking.

C. INDUSTRY REVIEW (cont.)

4. Doel Unit 4 (Belgium)

Doel Unit 4 experienced an event in the past when a lead object was inadvertently left in the steam generator. The event was reviewed extensively by various industry groups in an effort to establish and define the impact lead has on steam generator tubes and subsequent tube cracking. Doel Unit 4 experienced cracking in the freespan, tube support, and roll transition regions of the hot leg tubes. The results of the analyses on Doel Unit 4 were reviewed for applicability to the PVNGS events. While the presence of lead was found in PV Unit 2's SG's, the amount of Doel was substantially as a result the subsequent damage sustained at Doel would not be applicable to PVNGS.

5. EPRI

In 1991-1992 EPRI contracted with Dominion Engineering to investigate the extent and prevalence of freespan cracking in steam generators. Dominion surveyed recorded industry events and reviewed their database of eddy current results in order to ascertain the extent of freespan defects. The significant events reported at McGuire and Doel 4 (Belgium) were included in their review.

Dominion's investigation found that freespan indications were not confined to a single steam generator design nor were they singular in nature or cause. Some indications were long axial cracks that were found in the hot leg tubesheet crevices in part depth rolled units. Based on information available, Dominion was able to establish that the cracks were induced by caustic IGSCC. Other freespan defects were believed to have been the result of tube manufacturing or installation activities. Based on Dominion's findings, these types of defects have not been significant in number or impact within the industry.

The scope and results of Dominion Engineering's survey are as follows:

- 17 plants containing 59 steam generators were surveyed.
- 15 of 17 plants had identified tubes with freespan OD indications.
- 11 of 17 plants had plugged tubes with freespan OD indications.
- 400 bobbin and/or MRPC identified freespan OD indications were found to have been randomly distributed.
- 105 freespan defects were plugged in the 17 plants.
- 92% (- 97/105) of the defects were plugged in the four Duke units.

C. INDUSTRY REVIEW (cont.)

5. EPRI (cont.)

- 8% (- 8/105) of the defects were plugged in the seven other units.
- 21 plugable defects were found by MRPC only.
- 42 freespan defects not found by ECT during the previous inspection resulted in plugged tubes.
- 135 sizeable freespan indications were re-identified during one or more cycles.
- 11% (12/105) of the plugable freespan defects > 39% were found after not being identified during the previous inspections.

In the course of the conversation EPRI stated that some cracking had been identified at Calvert Cliffs. (Subsequent discussions with Dominion Engineering found that the Calvert Cliffs' cracks were associated with burnishing marks and irregular deposits at the first supports.)

EPRI stated that deposits, due to solubility changes, had appeared approximately 1/2 way up on steam generator tubes at the Ginna and Surry facilities. EPRI stated that it was probable that those deposits had been formed during cooldown from a viscous mix of magnetite and water.

6. Dominion Engineering

Based on a recommendation of EPRI, Dominion Engineering was contacted via telephone on April 20, 1993 and April 25, 1993 for additional information regarding the study they had performed for EPRI (see previous pages). It was Dominion's opinion that the best information regarding midspan cracking could be provided by the McGuire facility. Dominion stated that polishing and straightening stresses could be 10-15 ksi (thousand pounds per square inch) but that scratches could not be ruled out as a cause. Dominion stated that the problems experienced at Doel were aggravated by the existence of a lead blanket in the steam generators.

It was their recommendation that PVNGS contact Florida Power and Light (St. Lucie) for additional information regarding their experiences with steam generator tube cracks/indications. Dominion stated that they were aware of eggcrate cracks where line contacts between a tube and eggcrate could develop into a residual crevice. Pulled tubes at both Arkansas Nuclear One, Unit 2 and St. Lucie confirmed that evaluation. Dominion Engineering was not aware of any detailed evaluations on freespan cracking and could only provide speculation regarding the cause and process.

FIGURE IV.B.d

IGA/IGSCC Synergism

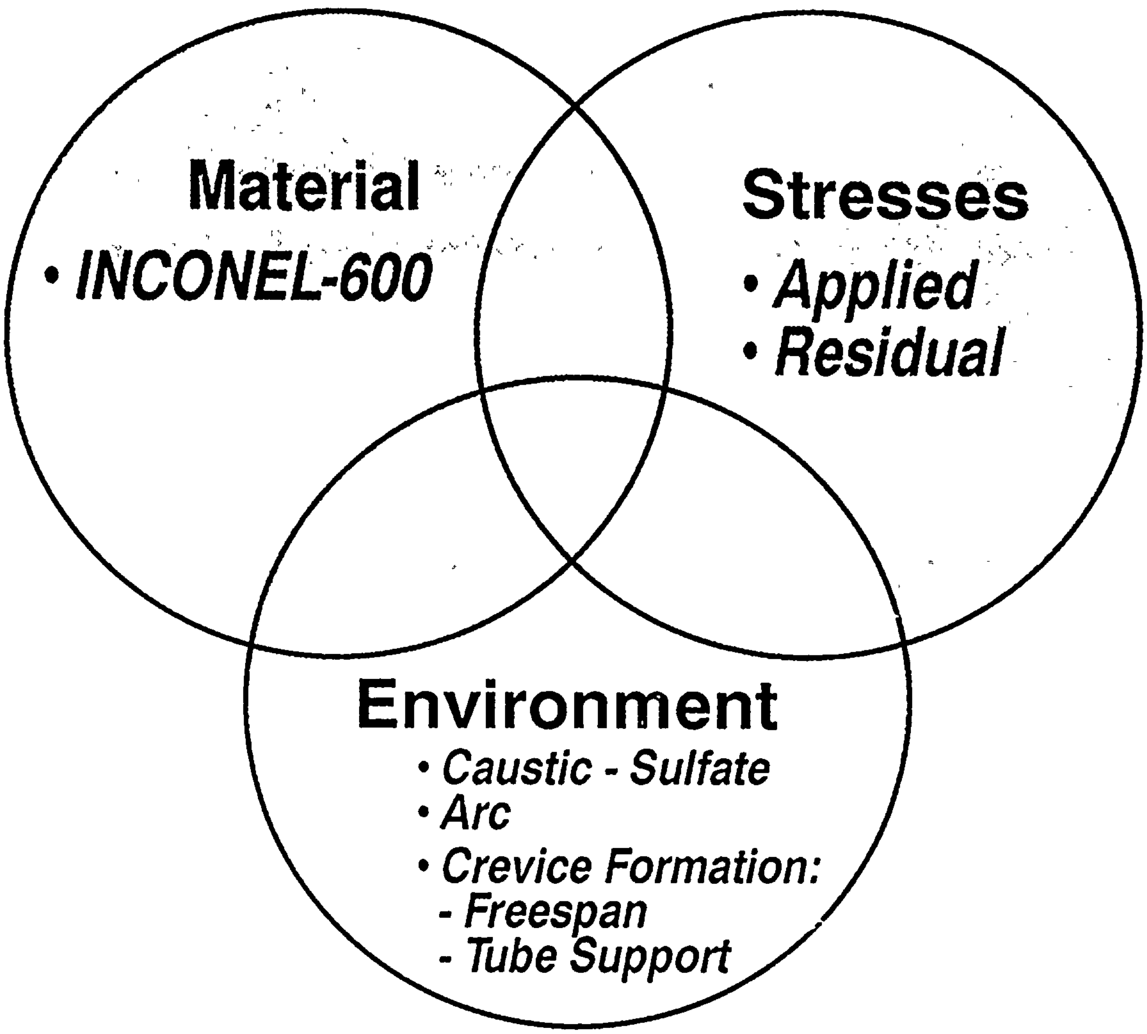


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FIGURE IV.B.c

Root Cause Worksheet

Factors	Supporting Evidence	Refuting Evidence	Possible Causes	Potential Future Confirmation	Potential Corrective Actions
1) Alkaline environment with possible aggravators	• Resin intrusions (7/91, 1/92) • S, Pb, Cu, Na - sludge & deposits • IGA deep in some locations • Higher hide-out return for Na, SO_4 in U-2 vs U-1/3 • Multeq and molar ratios support caustic crevice chemistry • Visual observation of resin on can deck • Metallurgical analysis supports alkaline and sulfide in oxide film	• Affects entire Steam Generator • Mixed metallurgical results • Tubing microstructure is not sensitized • No pitting or wastage is present	• Condensate demineralizer retention screen performance • Inadequate resin monitoring • Condensate demineralizer operation	• Tube deposit analysis • Multeq/hideout return chemistry • Sludge sampling in U1R4 • Future tube pulls	• Min/max chemistry • Improve/reduce use of condensate demineralizers • Institute resin control program • Boric acid
2) Freespan crevice formation	• Visual inspection (above 08H, near 09H) • Bridging deposits (visual & eddy currents) • Bowing measured in Lab samples • Numerous deposit pairs at same elevation in adjacent tubes • Lateral tube spring after whip cut	• Some deposit pairs observed outside of arc region	• Design (supports, upper tube bundle flexibility, thermal expansion, dead weight) • Fabrication (tubes vertical length, bending dimension variation) • Operation (flow induced vibrations	• Secondary inspection • MRPC program U1R4 • ECT proximity probe • Thermal growth analysis • Model boiler test	• Preventive plugging sleeving
3) Contaminant concentration in crevices (ridge deposits and supports)	• Previous high corrosion product transport • Several cracks (including the deepest) are under ridge deposits • Thermal hydraulic model supports arc region deposition • Ridge deposits concentrate most contaminants • Long continuous full power run time	• IGA found under general deposits	• Voiding induced concentration mechanism (local superheating) • Previous high corrosion product transport • Length of continuous high power run • Higher temperature at tube-to-tube contact	• ATHOS III • Degradation modeling • Enhanced low frequency ECT • PDP Study	• Periodic down power • T_{HOT} reduction • ETA/elevated pH • Blowdown optimization • Chemical cleaning
4) Flow-induced vibration (cold work & stress) (APS specific)	• 117-40 at 09H shows impact - wear marks between streaks of cracks • Some cracks are not under ridge deposits • Impact mark on 09H (116-41) • More tube wear in U2 and more in SG 22 than SG 21 • Analysis shows FIV is possible • Rupture location more susceptible at high amplitude points	• No clear fatigue transgranular cracking • Only an accelerant propagation (not initiation) • No evidence of tube to tube interaction	• Fabrication (bowing) • Damaged VS2 support • Level oscillation • Area of flow instability due to design or support inactivity	• ATHOS III • Wear/crack correlation • Secondary Inspection • Complete FIV analysis	• T_{HOT} reduction • SG Water Level Program change • Reduced power operations
5) Fabrication induced stresses (cold working/scratches)	• Scratches were found • Deepest cracks are associated with scratched areas	• Not all IGA/IGSCC associated with scratches	• Assembly (tube insertion) • Tube bending manufacturing	• Stress field measurements • Future tube pulls	• None
6) Tube manufacturing (Not APS specific) (Not Unit specific)	• No grain boundary carbides • Tubes 117-144, 105-156 103-156 less than acceptable	• Tubes 117-40, 127-140 had acceptable microstructures	• Improper heat treatment	• None	• None
7) Eddy Current testing detectability	• 30 tubes with cracks found by MRPC that were not found by bobbin • Non-detectable defect to rupture in one operating cycle • Several non-detectable defects exceeded Reg. Guide 1.21 in one cycle • Cracks exceeded Reg. Guide 1.21 limits in U2R3	• ECT program consistent with EPRI and regulatory recommendations	• Pilgering noise • Crack orientation ligament branching difficult to detect • Limitations of ECT technologies/guidance	• Metallurgical and burst test results • Average depth vs. maximum depth	• Improved technologies • Improved training • Alternate plugging criteria

7793
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FIGURE IV.B.b.

Root Cause Investigation Team -- SGTR Event Failure Modes

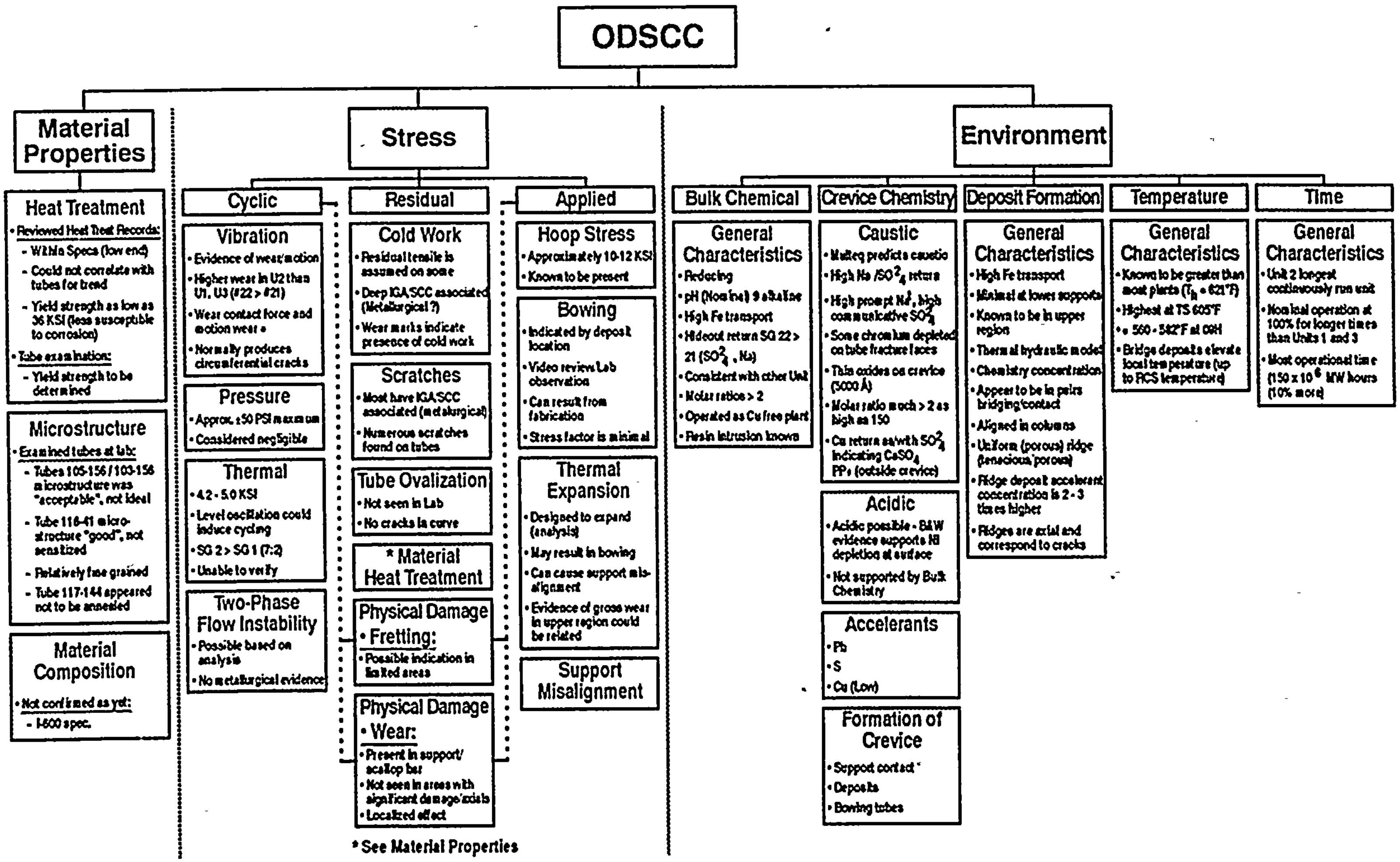
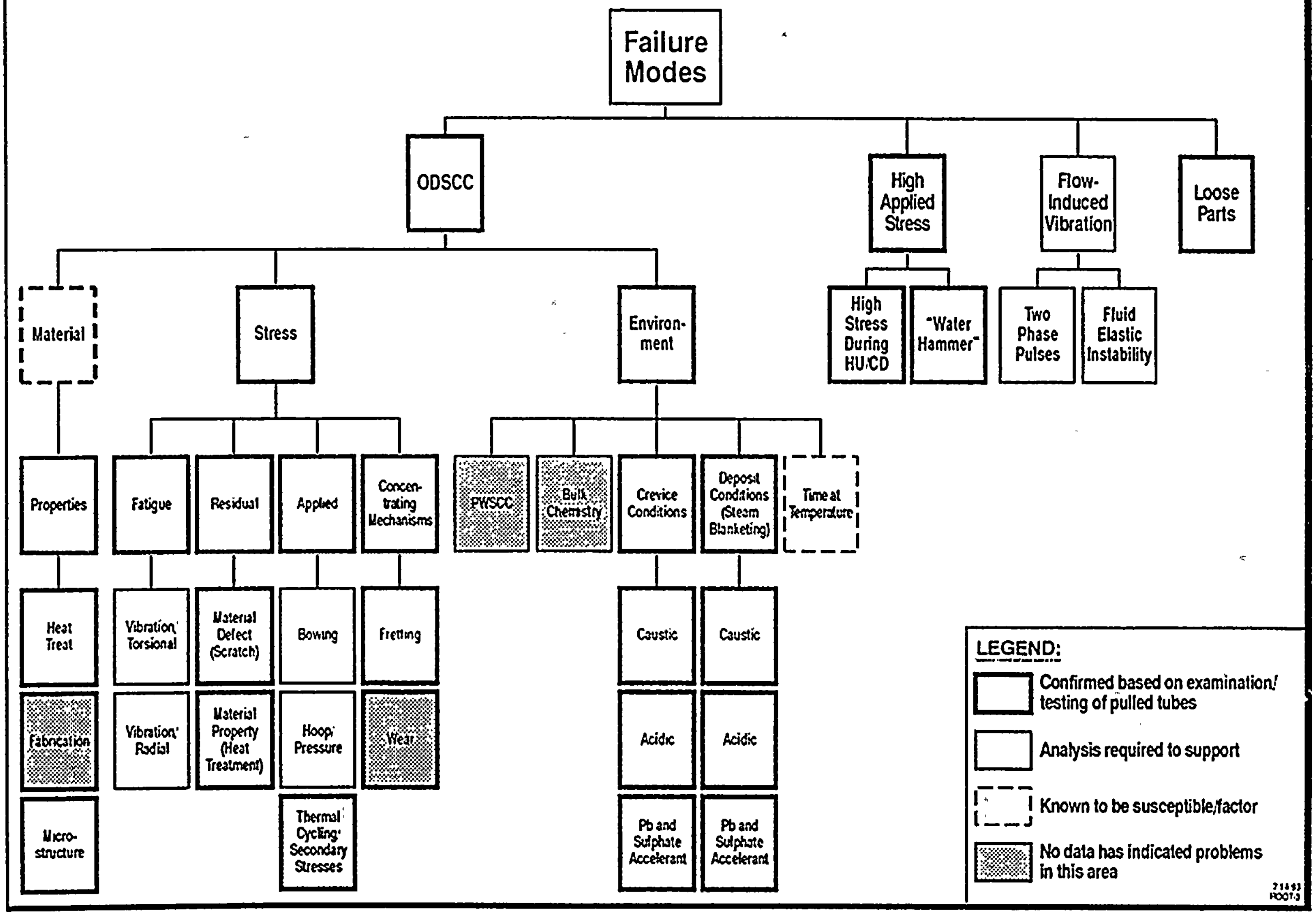


FIGURE IV.B.a

Root Cause Investigation Team - SGTR Event Failure Modes



IV. FAILURE MODE INVESTIGATION (CONT.)

C. INDUSTRY REVIEW (cont.)

7. Florida Power and Light

Based on the recommendation of Dominion Engineering, Florida Power and Light was contacted on April 25, 1993. FP&L Industry Review stated that St. Lucie had not identified any mid-span indications on their steam generator tubes. They stated that the cracking problems occurring at St. Lucie were ODSCC and IGSCC at supports. They stated that hundreds of defects were present in the eggcrates. They had also observed steam blanketing on horizontal runs due to the vertical straps acting as steam traps. (NOTE: The System 80 design has ventilating holes in the straps to prevent this from occurring.) FP&L suggested that lift off of ECT from ovalization should be evaluated as to whether such action could cause the bobbin to miss an indication. FP&L also stated that Turkey Point had hundreds of random burnishing points but, to date, no cracking had been observed at mid-span.

V. TROUBLESHOOTING ACTION PLAN/RESULTS

A. EDDY CURRENT TESTING

1. ECT Scope and Subsequent Expansions

a. Original Scope of ECT for Unit 2

Original Scope of eddy current testing for Unit 2's fourth refueling outage was developed based on: Technical Specification Surveillance requirements, EPRI recommendations, and consideration of the type and location of previously identified flaws and/or indications. Previous tubing indications that had been identified in Palo Verde's SG's included:

- Axial cracking found at the top of the tubesheet in Unit 1.
- Axial cracking found at the 01H flow distribution plate in Unit 2.
- Axial cracking found above the 09H free span in Unit 2.
- Wear at the cold leg corners, batwings, and vertical straps.
- Loose parts with and without associated wear.

Problems identified by other utilities, vendors, and the NRC have included:

- Circumferential and axial cracking at the tubesheet and/or tube supports.
- Denting and cracking next to the stay rods.
- Cracking in short radius bends.
- Crevice cracking or attack in non-expanded tubes.

The original scope included bobbin coil examinations on 100% of the tubes in each Unit 2 SG. Inspection was planned using the motorized rotating pancake coil for a minimum of 10% of the tubes at the expansion transition and first support locations on the hot leg side.

b. Initial Outage Plan/Results

The fourth refueling outage for Palo Verde - Unit 2 began on March 14, 1993, due to a steam generator tube rupture. The original outage schedule was to begin on March 20, 1993. The initial examination plan for both steam generators was a 100% full length bobbin examination with approximately 10% of the tubes to be tested using MRPC for the 01H and TSH intersections. The tubes were to be examined full length with the exception of some row 1, 2, and 3 tubes which were examined through the U-bend from both the hot and cold legs.

A. EDDY CURRENT TESTING (cont.)

1. ECT Scope and Subsequent Expansions (cont.)

b. Initial Outage Plan/Results (cont.)

After the manways were removed, the secondary side of the SG 22 was filled until the leaking tube could be identified. Visual examination confirmed that row 117 column 144 was the leaking tube. Eddy current probes and a Welch Allyn video probe was used to characterize the tube leak. It was determined that the leaking tube had an approximate 8 inch long mid-span axial indication located 34 inches above the 08H support. A 2 inch long fishmouth rupture was found in this tube starting 1 inch above the start of the 8 inch axial indication.

The eddy current testing began on April 11, 1993. Initial results identified a number of tubes with indications of axial cracking. The majority of the indications was located in the upper area of the hot leg side in SG 22. As a result of this initial testing, the scope of the testing in both generators was expanded. The scope was then systematically expanded as additional flaws were detected.

c. Unit 2, Steam Generator 21

First Expansion

During the third refueling outage (U2R3), a mid-span axial indication was found 3 inches above the 09H support in row 117 column 54. Since the axial indication in U2R3 and the ruptured tube were on the same row, the first examination was performed on rows 116 through 118 in each steam generator. Bobbin and MRPC examinations performed on these rows found a greater amount of wear indications in the 08H and 09H supports than expected. The next axial indications were found in rows 104 and 105. As a result, approximately 150 tubes were tested surrounding these tubes and a symmetrical spot on the other side of the generator.

Second Expansion

The second eddy current expansion consisted of testing all bobbin indications via MRPC to distinguish between wear and axial indications. On tubes with indications located from the TEH to the 09H, MRPC was performed on the 01H and TSH support locations. This was in order to satisfy the random approximate of 10% MRPC of the 01H and tubesheet.

A. EDDY CURRENT TESTING (cont.)

1. ECT Scope and Subsequent Expansions (cont.)

c. Unit 2, Steam Generator 21 (cont.)

Third Expansion

The purpose of the third MPRC expansion was to try and bound the single axial indication (SAI) band found in SG 21 and SG 22. After plotting the axial indications, it appeared that they followed an "arc" that started at around row 100 column 25 and continued to row 100 column 165. The arc was three to ten tubes in from the periphery of the tube bundle.

Fourth Expansion

The fourth expansion was a checkerboard expansion to MRPC the upper supports to try and find any axial indications outside the arc not found by the bobbin examination in SG 21. This expansion consisted of approximately 124 tubes.

Fifth Expansion

The fifth expansion was to bund axial indications found on the edge of the arc expansion (third expansion) and to see if the arc continued below row 100.

Sixth Expansion

The sixth expansion consisted of testing tubes around the periphery from BW1 to VS3. This was done to test within the arc region in the horizontal sections of the tubing.

Seventh Expansion

The seventh expansion was to make the arc of interest larger to match the thermal-hydraulic modeling performed using the ATHOS modeling program. The arc was expanded to include row 90.

Eighth Expansion

The eighth expansion extended the arc to match the refined modeling done in expansion seven. This increased the arc to an area of interest including row 70.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

A. EDDY CURRENT TESTING (cont.)

1. ECT Scope and Subsequent Expansions (cont.)

c. Unit 2, Steam Generator 21 (cont.)

Ninth Expansion

The ninth expansion consisted of testing groups of tubes that were outside the arc, from the BW1 support down to the 01H support.

Tenth Expansion

The tenth expansion tested tubes within the arc from the BW1 to VS3 support using the flexible MRPC probe. The testing was performed in the arc in four separate blocks scattered around the area of interest.

Eleventh Expansion

The eleventh expansion tested tubes full length within the arc from the 07H down to the 01H support. This was done in order to check for indications in the lower sections of tubing below the arc.

Twelfth Expansion

The twelfth expansion tested tubes in groups outside the arc. Testing of these tubes varied from part length to full length examination. The purpose of this expansion was to outline the amount and type of indications outside the area of interest.

Thirteenth Expansion

The thirteenth expansion tested tubes inside the arc from the BW1 support to the first VS encountered.

d. Unit 2, Steam Generator 22

First Expansion

Due to the tube pulling activities, the eddy current examination was stopped in SG 22. Eddy current testing continued in SG 21, however. The expansion groups were consolidated when the tube pulls were completed. The first expansion consisted of the original arc and rows 116, 117, and 118.

A. EDDY CURRENT TESTING (cont.)

1. ECT Scope and Subsequent Expansions (cont.)

d. Unit 2, Steam Generator 22 (cont.)

Second Expansion

The second expansion was to test via MRPC all indications found by the eddy current bobbin probe.

Third Expansion

The third expansion was to increase the original arc to match the seventh expansion in SG 21.

Fourth Expansion

The fourth expansion was done in order to have the arc in SG 22 match the thermal-hydraulic modeling performed using the ATHOS computer modeling program. This expansion went down to row 70.

Fifth Expansion

The fifth expansion tested tubes in groups outside the arc, from part length to full length examination. The purpose of this expansion was to outline the amount and type of indications outside the area of interest.

Sixth Expansion

The sixth expansion consisted of testing tubes inside the arc from the BW1 support to the first VS support encountered.

A. EDDY CURRENT TESTING (cont.)

2. Eddy Current Inspection Results

The daily progress of an evolving eddy current testing in the Unit 2 steam generators was followed closely by the Task Force. The exams included 100% Bobbin coil eddy current and extensive MRPC examinations of both SG 21 and SG 22. The original scope of ECT planned for the U2R4 outage was a 100% bobbin coil inspection and a 10% random MRPC inspection for the tubesheet and flow distribution plate cracking. This original inspection was planned so as to locate axial cracking at the tubesheet and the 01H flow distribution plate, axial cracking in freespan locations, wear at the cold leg corners, batwings, and vertical straps, and loose parts.

During the previous outage (U2R3), one (1) tube (R117C54) was found to have an upper bundle region axial defect (which was located in the freespan region between the two partial eggcrates 08 and 09). It should be noted that two (2) plugged tubes (R112C151 and R134C97) originally classified as potential loose parts during U2R3 were reviewed during this outage and based on the characteristics of the defects could now be classified as axial defects near the batwing supports.

Due to the number of defects found during the ECT during the U2R4 outage, 13 MRPC expansions were made to the original ECT scope in SG 21 and 6 expansions in SG 22. A summary of the types of MRPC sampling performed in U2R4 and the basis for inspection is provided below:

- **Justification for MRPC Sample Plan**

  There were two objectives of the MRPC program. The first was to perform a thorough inspection of the area of the steam generator in which a disproportionate number of axial indications had been detected. That area of the steam generator corresponds to an area that thermal-hydraulic analysis predicts has a higher propensity for solids and contaminant deposition as described in Section V.P. The second objective was to perform sufficient MRPC inspections outside the area of interest to demonstrate that probability of defects below bobbin coil detection outside the area of interest would be acceptable and would not represent a challenge to the safe operation of the facility.

  Performance of extensive MRPC inspections in the region that exhibited a disproportionate number of bobbin coil indications and limited MRPC inspections in areas not exhibiting unusual amounts of bobbin coil indications would be in accordance with accepted industry practice.

A. **EDDY CURRENT TESTING (cont.)**

2. **Eddy Current Inspection Results (cont.)**

- **Justification for MRPC Sample Plan (cont.)**

(1) Definition of Arc Segment Area of Interest

An area of interest with a disproportionate number of axial indications exists near the outer periphery of the tube bundle (Figures V.A.1 and V.A.2). As described in Section V.P.2.b, thermal-hydraulic analysis results indicated there was a higher propensity for deposition in an area near the outer periphery of the tube bundle extending from the tube bend on the hot leg side down to approximately the 07H horizontal eggcrate support (Figures V.P.4 through V.P.14).

Based on thermal-hydraulic analysis results, a deposit parameter was calculated as a function of mass flux (density times velocity) and steam quality and provides a mechanistic explanation for the disproportionate number of indications in this area. The parameter provides a correlation with the apparent trend of deposit locations. The majority of the deposit indications are concentrated in the area of highest deposit parameter. Empirical data available in industry literature suggests that when this parameter exceeds a certain value, a transition to film boiling occurs (as opposed to the more desirable nucleate boiling) and, with that, an increased propensity for deposition. The data suggests this value to be approximately 0.7 (normalized to PVNGS values). That value results in an agreement with actual deposit indications and can be used to define the area of interest to be subject to MRPC inspection.

Using 0.7 as a general guide for defining the MRPC program, an MRPC inspection pattern was developed (see Figure V.A.3) with the objective of conservatively bounding the axial indications observed and provide an inspection of the area identified by the thermal-hydraulic analysis. Approximately 3800 tubes comprise this arc segment and have been MRPC inspected as a minimum from the first VS support down to 08H including the tube bend. As indicated in Figures V.A.4 and V.A.5, all upper bundle axial indications, whether in the mid-spans or at a support, are contained within the inspected region.

A. EDDY CURRENT TESTING (cont.)

2. Eddy Current Inspection Results (cont.)

- **Justification for MRPC Sample Plan (cont.)**

(2) MRPC Inspections Beyond Arc Segment

To support the conclusion that the area of interest had been adequately defined, additional MRPC inspections beyond the defined boundaries of the arc were performed. These included:

Five hundred (500) tubes in SG 21 and in SG 22 with bobbin coil indications, located throughout the tube bundle, were inspected by MRPC with no axial defects found outside the area of interest. If a significant number of axial indications existed outside the arc, some percentage of those indications should have been detectable by bobbin coil. One indication located in a tube within the arc at support 05H was identified in SG 22. Since only one bobbin detectable indication of this nature exists in SG 22, the population of axial indications not detectable by bobbin outside the area of interest is very low. Additional MRPC of tubes surrounding this indication was performed and no additional indications were identified.

Tubes in a checkerboard pattern, groups of tubes located radially inward from the arc, and groups of tube segments of tubes within the arc but below (inspected below 08H) the defined area of interest were randomly selected and inspected. Table V.A.1 and V.A.2 provides an accounting of the number of tubes inspected and the vertical extent of the inspections. The location of the tubes inspected outside the arc and those within the arc inspected below 08H is illustrated in Figures V.A.6, 7, 8, 9, 10 and 11. No axial indications were detected during the random inspections.

Due to the lack of indications found during these MRPC inspections, it was concluded that any significant degradation was contained within the defined area of interest.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

A. EDDY CURRENT TESTING (cont.)

2. Eddy Current Inspection Results (cont.)

- **Justification for MRPC Sample Plan (cont.)**

(3) 07H to 08H Mid-span and 07H Inspections

The vertical extent of the area of interest was originally considered to be from BW1 to 08H. Subsequent thermal hydraulic analysis results confirmed the highest propensity for deposition was from BW1 to 08H. However, it was decided that inspections down to 07H, roughly corresponding to a deposit parameter of 0.7, would provide greater assurance that the vertical extent of the area of interest had been bounded. A total of 1065 tubes in SG 21 and 489 tubes in SG 22 out of the 3800 tubes contained within the arc have been inspected down to at least the 07H support and an additional 1999 tubes in SG 21 and 3300 tubes in SG 22 were inspected at the 07H (i.e., were inspected continuously from BW1 to 08H and then also at 07H) using MRPC. There were no NBI's (NBI is a MRPC call not found by bobbin) found below the 08H support.

(4) Statistical Analysis

A statistical analysis was performed of the Unit 2 steam generator MRPC and bobbin coil inspection programs to estimate the number of axial indications not detected by bobbin coil outside the arc that might be detected by additional MRPC. A traditional statistical approach was used in which the area of disproportionate bobbin indications would be treated as a high risk area, and areas not exhibiting unusual numbers of bobbin indications would be treated as low risk. This analysis concludes there is high confidence (95%) that there would be a limited number of axial indications (x or less total and x or less mid-span defects) outside the arc uncovered by MRPC inspection. For comparison purposes, the EPRI-recommended 20% random sample (EPRI NP-6201), which is an accepted method for establishing sampling scope, allows the utility to suspend sampling if 90% confidence of fewer than 12 defects is achieved. Accounting for some analysis uncertainties, the results would still indicate that additional sampling outside the defined arc segment is not required.

A. EDDY CURRENT TESTING (cont.)

2. Eddy Current Inspection Results (cont.)

- **Defects found during Unit 2 Inspections**

The ECT results to date (July 6, 1993) indicate that the SG's had experienced axial cracking at the following locations:

- Support cracks at the 01H support and the tubesheet (Figures V.A.14 and V.A.15)
- Support cracks from the 05H to the 09H support
- Freespan cracks in the tube sections between the two highest partial eggcrates
- Support cracking at the batwings
- Freespan cracking between the batwing support and the vertical tangent to the U-bend (Figures V.A.12 and V.A.13)
- Freespan cracking at the horizontal tangent to the U-bend
- Support cracking at the vertical straps.

A summary of the entire inspection program is best displayed via tubesheet maps included as Figures V.A.3 through 15 and tabulated results given in Tables V.A.1 through 6.

In summary, an increased number of axial indications in the upper tube bundle were discovered during the inspection program. The indications were found to be concentrated near the outer periphery mostly between 08H and the tube bend. Some of these indications were detected by MRPC but not by bobbin coil. As a result, a concentrated MRPC program was conducted to ensure a thorough inspection by MRPC of the area in which the indications occurred. Upon completion of the MRPC inspection program, all the upper bundle indications had been well bounded by the MRPC inspection program. Additionally, sufficient MRPC inspections were performed in areas away from the area in which the indications occurred to provide confidence that the tube degradation was constrained to the area in which the concentrated MRPC program was conducted. Based on this program, APS is confident that all significant indications have been discovered.

B. ECT METHODOLOGY AND DETECTABILITY REVIEW

1. ECT Conditions and Methods at PVNGS

The primary method used to identify and define SG tube degradation on site was eddy current testing. Concerns regarding the validity of PVNGS' ECT methodology and detectability were identified (i.e., the possibility that the apparent increase in degradation indicated by 1993 ECT results was a function of problems with ECT methodology).

As a result, the ECT methodology was reviewed with attention focused on the PVNGS steam generator ECT program, ECT signal/noise ratio, standards, limits of detectability, and sensitivity.

- **PVNGS Steam Generator ECT Program**

The requirements and instructions for performing eddy current examination of steam generator tubing at PVNGS are provided in Station Manual Procedure 73TI-9RC01 "Steam Generator Eddy Current Examinations." The procedure implements the examinations required by ASME Section XI and PVNGS Technical Specification 3/4.4.4.

The procedure specifies equipment requirements, calibration standards, and personnel qualification and training. A primary and secondary analysis as well as computer data screening of all acquired bobbin coil data was performed. A lead analyst was designated for both the primary and secondary review companies. During U2R4, independent analysis was provided by designating lead analysts from two (2) ECT organizations - CONAM and CE. A Level III analyst was designated for the overall resolution and evaluation of eddy current indications. The following exam frequencies are normally utilized at PVNGS:

- 550 KHz Differential - used for detection and sizing to satisfy PVNGS Technical Specifications and ASME Section XI.
- 100 KHz Absolute - used for mix component and defect confirmation.
- 990 KHz Differential and Absolute - used for inside diameter mix component.
- 100 KHz Differential and Absolute - used for outside diameter mix component and tube support locating.
- 20 KHz Differential and Absolute - used for sludge, loose parts and tube supports locating.
- 550-100 KHz Differential - Mix 1, used to suppress tube supports, loose parts, deposits and etc., for detection and sizing.

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

1. ECT Conditions and Methods at PVNGS (cont.)

- **PVNGS Steam Generator ECT Program (cont.)**
  - 550-100 KHz Absolute - Mix 2, used to suppress tube supports, loose parts, deposits and etc., for sizing of wear at batwings, vertical straps, eggcrates, and the flow distribution plate.
  - 550-100 KHz Differential - Mix 3, same as Mix 1 except high span to detect indications at the roll transition.
  - 550-990-100 KHz Differential - Mix 4, used to suppress geometry changes (IDC, offsets, expansions, etc.) for detection. Save the 100%, 60% and 20% ASME signals and suppress the support and hot/cold leg roll transition signals.
  - Other frequencies and mixes may be utilized, provided they are documented on Acquisition and Analysis Technique Sheets in accordance with the procedure.

- **Standard Eddy Current Techniques at PVNGS**
  - Bobbin Coil

    The bobbin coil (see Figure V.B.1) is a widely utilized ID probe with high inspection rates of up to 24 inches per second. The eddy current flow is directed around the tube circumference and is primarily sensitive to volumetric and axially oriented degradation. The probe is sensitive to probe fill factor variations, where fill factor is a measure of the degree to which the ID space is occupied by the bobbin coil probe. As a result, tube ID variations such as tube wall corrugation due to pilgering may affect detection capability. Typically, PVNGS uses a size 610 bobbin probe for full length bobbin inspections. Smaller probes (i.e., 590 or 540) are used if obstructions from denting or ovality are encountered.

    Two techniques are utilized for eddy current examination at PVNGS. These are

    a. Absolute Mode: Current flow in the tube parallels the coils windings - satisfactory for detection of gradual discontinuities such as wear or tube thinning

    b. Differential: Two bobbin coils connected in series-opposition and separated by some distance so that their respective fields overlap a common region. This coil configuration responds more strongly to localized axial changes in tubing geometry such as cracking.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

1. ECT Conditions and Methods at PVNGS (cont.)

- **Standard Eddy Current Techniques at PVNGS (cont.)**
  - Motorized Rotating Pancake Coil

    The MRPC probe (see Figure V.B.2) is a small surface riding probe which is rotated and translated through the tube at much slower inspection rate of 0.2 inches per second. It is estimated that to perform a full length MRPC inspection of one tube would be approximately 1.5 hours or greater than 600 days to inspect a System 80 steam generator. PVNGS utilizes a standard three-coil MRPC which consists of an axial, circumferential and pancake (both directions) probe. The probe surface riding capability reduces lift-off as an extraneous test variable and is therefore less sensitive to tube ID variations.

    As the MRPC probe is translated and rotated through the tube, it describes a helical path. A linear discontinuity within the tube wall will be scanned once during each rotation. The MRPC coil output voltage from a given rotation is used to generate a line scan which represents a signal amplitude as a function of coil position around the tube circumference. Pseudo-image formation in a two dimensional cylindrical coordinate system is accomplished by plotting a series of consecutive line scans with line scan generation synchronized with probe rotation. Crack and/or deposit presence is determined by recognizing the existence of linear features in the reconstructed image; orientation is inferred by noting the direction of the major axis of the image. Generally, the MRPC is considered to provide better detection capability than bobbin coil. However, the increase in detectability is dependent on the type and orientation of the defect.

- **New ECT Technology Used/Evaluated During U2R4**

  To assist in ECT detectability issues and improve resolution of tubing condition, APS also evaluated and/or employed different inspection technologies during the root cause investigation. A description of the equipment and techniques considered by APS are provided.

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

1. ECT Conditions and Methods at PVNGS (cont.)

- New ECT Technology Used/Evaluated During U2R4 (cont.)

  - BWNS Electronic Rotating Field Eddy Current Probe (RFECT):

    BWNS has been evaluating the use of its RFECT probe to perform inspections of steam generator tubing. The probe has been in development for the past year and was tested at the Beaver Valley Unit 1 plant in a comparison with MRPC data for 122 intersections. The probe provides a terrain plot similar to MRPC but has acquisition speeds 2-4 times faster than MRPC. Similar to MRPC, the probe could be used to quantify the presence of defects without being used for through-wall sizing. BWNS examined Unit 2 tube pull specimens and tested several probes in the Unit 2 steam generators. Although the probe was not considered to be qualified for the U2R4 inspection, additional testing may demonstrate equivalent capabilities for future inspections.

  - CE High Resolution Bobbin (HRB) Probe or Segmented Bobbin:

    CE developed an HRB probe which has been used in an ongoing program of evaluation on laboratory samples, field testing and testing of tubes pulled from operating steam generators since the first prototype was completed in 1990. Multi-coil arrangements in the HRB probe provide a separate evaluation along each of the four quadrants around the tube circumference. This feature provides a potential improvement on signal resolution and estimates of axial and circumferential distribution of an indication. For inservice testing the HRB probes support hardware and software similar to that of standard bobbin coil examination. CE examined the Unit 2 tube pull specimens, and the results indicated a degree of increased accuracy for some defects. As with the BWNS probe, the HRB probe is not qualified for the U2R4 inspection, although additional testing may demonstrate enhanced defect screening capabilities for future inspections.

  - Flexible MRPC U-Bend Probes:

    Prior to U2R4, a three coil MRPC of the square bend and horizontal region of the System 80 steam generators could not be performed due to the rigidity of the MRPC probe and motor driver assembly. As a result of concerns regarding the performance of bobbin coil due to tube curvature and ovality, Zetec developed a flexible three-coil rotating pancake coil probe. The rotating section is eight feet in length as the motor driver remains in the vertical section of the tube.

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

1. ECT Conditions and Methods at PVNGS (cont.)

- **New ECT Technology Used/Evaluated During U2R4 (cont.)**

  - Magnetic Indexing Referencing (MIR) Probe:

    In order to determine the orientation of flaw and deposit indications within the tube bundle, a BWNS MIR probe was utilized. The orientation of the ECT indication was determined by inserting the MIR probe in a tube adjacent to the target tube while simultaneously inspecting the known indication elevation with MRPC. The magnetic field generated by the high energy magnets located in the MIR probe provided a reference for the MRPC signal characterization. In order to avoid distorting the MRPC signal the MIR probe is positioned in the locator tube below the known indication elevation. The MRPC probe positioned above the indication in the target tube is withdrawn past the indication and the MIR probe. Based on known SG geometry, orientation of the indications can be determined.

  - Video Inspection:

    The use of Welch-Allyn video inspections in the space left from pulled tubes assisted the ECT program in visually comparing the morphology of deposits with the MRPC deposit signals. The observed presence of freespan linear deposits validated the MRPC results.

  - 630 Bobbin Coil Probe:

    Due to bend restrictions this larger probe is not considered practical for performing full length bobbin coil inspections. The probe was used, however, within a number of straight hot leg sections to determine if a larger fill factor could provide enhanced detection capability. A total of 68 tube inspections with the larger 630 probe were performed. No conclusive evidence regarding enhanced detectability was observed.

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

1. ECT Conditions and Methods at PVNGS (cont.)

- **New ECT Technology Used/Evaluated During U2R4 (cont.)**

  - Mid-Frequency Bobbin Coil Probe:

    The bobbin coil probe used by APS for the original 100% full length ECT examination is specified as a high frequency coil. The coil is tuned to function effectively at 550 kHz, which is the prime frequency for 0.042 inch wall tubing. The high frequency range of this coil, however, reduces its efficiency of the 100 kHz channel compared to that of a mid-frequency coil. The 300-100 mix has greater SN ratios than the high frequency probes. Industry experience, in older Westinghouse units with open crevices, has shown that the 100 kHz absolute channel can be used to screen for drift, or absolute positive traces, which may be indicative of IGA/IGSCC.

    A small sample of tubes were tested with this probe to determine if improvements in detectability could be realized. Preliminary results did not indicate enhanced flaw detection; however, deposit indications, previously undetected by bobbin coil, provided signals in the 20 kHz channel.

  - Ultrasonic Testing (UT) Probe:

    The use of UT was considered by APS to verifying bobbin coil and MRPC detectability threshold. However, based on discussions with CE and BWNS, the use of UT was not regarded to be an inspection improvement in terms of detectability and/or inspection production rates. At ANO-2, ultrasonic shear wave testing was conducted to assess the nature and severity of circumferential and axial OD cracking. The testing was performed by NUSON Inc., a recognized industry leader in this field. UT failed to detect the presence of axial indications found with ECT techniques. Additionally, the UT consistently undersized the average depth of the ANO-2 tubesheet indications. Furthermore, a review of UT production rates found that inspection speeds for UT were 2-5 times slower than MRPC without a corresponding gain in detectability.

    APS has not ruled out possible use of UT examinations of steam generator tubing in the future; however, additional qualification testing would be required prior to field deployment.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

1. ECT Conditions and Methods at PVNGS (cont.)

- **Bobbin Coil Re-evaluation:**

A bobbin coil reevaluation was performed on rows 90 through 159 in both steam generators in Unit 2 for the purpose of determining if changes in analysis techniques as well as analyst training could be implemented to provide enhanced detectability of these defects. The emphasis of the reevaluation was placed in the identified area of interest between 08H and the batwing support (BW2). The following techniques were used:

a. Provide training to analysts on defect characterization.

b. Increase the P1 mix channel (550-100 KHz differential) amplitude.

c. Zoom the CRT strip chart to enhance the display in the area of interest.

d. Scroll through the data, examining the P1 vertical signal in the strip chart for distortions in the ID chatter. Report anomalous signals as non-quantifiable indications (NQI).

e. Scroll through the BW1 and BW2 with 100 KHz differential for wear indications.

f. Scrutinize data above BW1 to the vertical strap region.

Using this methodology, the number of NBI would be reduced. Typically, the reevaluation would report these locations as NQI which by procedure requires inspection by MRPC, therefore provides a detectability level equivalent to MRPC limits. APS intends to incorporate these techniques in a revision to 73TI-9RC01 and future ECT analysts training.

2. Eddy Current Detectability

In determining detectability thresholds for IGA/IGSCC and their impact to the PVNGS Unit 2 steam generators inspection plan, several factors were considered.

- Industry experience for OD initiated IGA/IGSCC.
- Results from destructive and non-destructive laboratory testing of tube pull samples including burst test results.
- Effects of extraneous test variables such as pilger noise.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

2. Eddy Current Detectability (cont.)

a. Industry Experience

Nuclear Regulatory Commission (NRC) Information Notices 91-67 "Problems with Reliable Detection of Intergranular Attack (IGA) of Steam Generator Tubing" and 90-49 "Stress Corrosion Cracking in PWR Steam Generator Tubes" highlight an industry issue regarding detection of corrosion related damage of Alloy 600 steam generator tubing. EPRI, working with member utilities via the Steam Generator Reliability Project, has attempted to address these concerns by implementing enhancements to its inservice inspection (ISI) guidelines in the areas of equipment and analyst qualification. Additionally, EPRI has been leading an effort towards reliance on a volumetric based plugging criteria for ODSCC. Likewise, the NRC has recently issued Draft NUREG 1477, "Voltage-Based Interim Criteria for Steam Generator Tubes - Task Group Report," which provides the NRC position on ECT capability for detection and sizing of ODSCC defects. The Task Force has reviewed the industry data and concludes that, in principle, the data supports the detectability limits proposed by APS for its Regulatory Guide 1.121 evaluation given in Section X, Unit 2. Steam Generator Tube Rupture Analysis Report, July 1993. The Task Force has reviewed specific industry references to provide comparative information in support of the conclusions of this section. The results of this review are provided next.

As reported in EPRI document NP-7480-L the morphology of intergranular corrosion explains the reduced eddy current response for small cracks. The observed field degradation, multiple short cracks coupled with an intergranular nature of the cracks, allows paths for the eddy currents to pass uninterrupted through the degradation. An appreciation for why this phenomenon occurs comes from the use of liquid metal modeling techniques. Using this technique, degradation is simulated as inserts in the liquid metal, and degradation morphologies that are difficult or impossible to machine (EDM notches) can be easily simulated. The difference in "real" cracks and notches have been modeled by varying the contact between the faces of the crack. This work showed that interfacial contact of 50% could reduce eddy current response by a factor of five. This same factor was identified by Dr. C.V. Dodd of the Oak Ridge National Laboratory in a June 8, 1993 letter from the NRC to APS. In Dr. Dodd's report the estimated detection levels for bobbin coil and MRPC were 70% and 50% respectively for crack-like defects at PVNGS. However, it is APS's position that a definitive correlation can not be drawn from the liquid metal testing due to the inability of quantifying the level of ligament bridging or interfacial contact of the PVNGS defects. The actual PVNGS tube examination results provide a better baseline for comparison with industry data.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

2. Eddy Current Detectability (cont.)

a. Industry Experience (cont.)

APS Memorandum 281-00864-MAR/KMS dated June 30, 1992, provided the results of a review performed by Nuclear Engineering and the Inservice Inspection Department of NRC Information Notice 91-67. Although NUREG 1477 and IN 91-67 report problems with detection of defects greater than 70% through-wall at the Trojan facility, it is the APS position that ECT programmatic deficiencies at Trojan may not be a representative data point when compared to the rest of the industry. Conversely, EPRI has conducted testing in support of the recently developed Appendices G and H of the EPRI ISI Guidelines with regard to the ability of bobbin coil techniques to identify ODSCC type defects. The test program showed that although bobbin coil examinations were not necessarily accurate in estimating crack depth, a high level of confidence of discovery (85% probability of detection (POD) at a 90% confidence level) could be realized for defects between 40-59% through-wall. This threshold of detectability is consistent with the PVNGS limits, as well as other tube pull examinations performed by McGuire, ANO-1 and Beaver Valley.

b. PVNGS Tube Pull Laboratory Results

From the inventory of eight tube sections removed from SG 22, six areas with axial cracking were selected to be burst test in the laboratory. After burst testing, crack profiles were generated for each crack location to allow direct comparison with eddy current results. Table V.B.1 provides a compilation of actual measured crack depths/lengths, corresponding field bobbin, field MRPC indications, measured burst pressure, and calculated burst pressures based on actual measured average crack depth and length. Cracks that were detected by field bobbin are indicated by a NQI, distorted support indication (DSI), or numerical entry in the "Field Bobbin" column. An NBI entry in this column indicates the crack was not detected by bobbin coil inspection. Cracks detected by MRPC are indicated by an SAI or multiple axial indication (MAI) in the MRPC column. An NDD entry indicates the crack was not detected.

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

2. Eddy Current Detectability (cont.)

b. PVNGS Tube Pull Laboratory Results (cont.)

From the data presented in Table V.B.1 (referenced previously), Figure V.B.3 provides a graphical illustration of the percent of cracks detected by both bobbin and MRPC for ranges of actual crack sizes from the population of cracks found on the pulled tubes. The information provided detectability comparisons of bobbin and MRPC for axial crack indications based on average through-wall depth. As shown, the eddy current detectability threshold for 100% detection, based on average crack depth, is 50% through-wall for bobbin and 40% through-wall for MRPC. Those detectability thresholds are consistent with current industry guidelines.

Figure V.B.4 provides a similar detectability determination based on maximum crack depth. To determine which comparison is appropriate for use as a detectability threshold, a comparison of the actual burst pressures versus the predicted burst pressures based on average and maximum crack depths is provided in Table V.B.1 and illustrated in Figure V.B.5. The comparison demonstrated that a correlation with actual burst pressures can be achieved using the average crack size. Thus, the average crack size is more indicative of the structural integrity of the tube than the maximum crack size. Therefore, 50% average through-wall depth will be used as the bobbin coil detectability threshold. Similarly, 40% through-wall will be used as the MRPC detectability threshold. The detectability thresholds are utilized in the Regulatory Guide 1.121 evaluation.

- Noise Level Effects

  - Description of PVNGS System 80 Steam Generator Tubing

    The tubing material installed in the PVNGS System 80 steam generators is a high temperature mill annealed (HTMA) alloy 600. The tubing for Units 1 and 2 was manufactured by Noranda, and Unit 3 tubing was supplied by Sandvik. The tube extrusion was accomplished utilizing a pilgering process. With the exception of the Palisades replacement steam generators, no other Combustion Engineering generators use pilgered tubing. The Millstone 2 replacement steam generators were manufactured by B&W Canada with pilgered Inconel 690 tubing. Tubing manufactured for pre-System 80 plants was cold worked via a bench drawing process.

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

2. Eddy Current Detectability (cont.)

- **Noise Level Effects (cont.)**

  - Description of PVNGS System 80 Steam Generator Tubing (cont.)

    Both cold drawing and pilgering operations are depicted in Figure V.B.6. Although most Combustion Engineering, Westinghouse and Babcock and Wilcox original steam generators have been supplied with drawn tubing, most recent replacement steam generators were ordered with pilgered tubing. The choice between pilgering and drawing involves both technical and economic considerations for the utility. For example, the amount of wall thickness reduction per pass during extrusion is typically high for pilgering and low for drawing, and therefore pilgered tubing can be manufactured quickly and economically. Alternatively, inservice inspectability is decreased for pilgered tubing due to internal surface corrugation which results from the pilgering process. Pilgered tubing typically has eddy current noise levels two to four times that of drawn tubing (see Table V.B.2, Figure V.B.7). It should be emphasized that ID irregularities from the pilgering process do not cause or indicate defective tubing but require that measures be taken by the purchaser in specifying manufacturing limits for signal-to-noise ratios or in the utility inservice inspection programs to account for the impact of pilger noise on inspectability.

  - Signal to Noise Ratios:

    Eddy current noise levels depend to a great extent on the surface condition of the inside diameter of the tubing; the smoother the ID, the lower the noise. "Macro" irregularities such as corrugation or grooves rather than surface roughness (RMS) may impact eddy current detectability. Excessive tube noise or "pilger noise" may:

    - Mask small amplitude eddy current signals resulting in non-detection of tube wall degradation.

    - Require a decrease in the plugging limit if excessive sizing error is required to support Reg Guide 1.121 design basis.

    - Permit repairable defects to remain inservice due to incorrect sizing of small amplitude indications.

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

2. Eddy Current Detectability (cont.)

- **Noise Level Effects (cont.)**

  - Signal to Noise Ratios: (cont.)

Tube noise is not typically a concern for most drawn tubing, although some ID chatter or support location residual noise can impact eddy current detectability in steam generators with drawn tubing. With pilgered tubing, tube noise levels can be controlled during the manufacturing phase by specifying a minimum acceptable signal-to-noise (S/N) ratio. Laborelec and EPRI have indicated that a S/N ratio of 3 is a minimum consistent with detection of defects, and that a S/N of 10 is desirable for good defect depth determination. The minimum 3:1 ratio is a historically accepted value derived from basic signal detection theory. Recent specifications for replacement steam generators have typically required S/N ratios of 5-7 for pilgered tubing. The original specification for the PVNGS System 80 steam generators did not specify a minimum S/N ratio in either the tubing material or non-destructive examination (NDE) requirements sections. However, the purchase order issued to the tubing manufacturer did contain noise level acceptance criteria. For Unit 1, tubes with an average horizontal indication exceeding 400 millivolts and vertical indication of 100 millivolts were rejected. This criteria was revised to 800 mv and 150 mv for Units 2 and 3, respectively.

APS has reviewed eddy current data for all three units in an attempt to determine an average S/N ratio for each PVNGS steam generator. The methodology used was similar to the approach presented by EPRI. The signal source was a 0.052 in diameter ASME hole standard, and was compared to the noise generated as a result of ID and wall thickness variations. The signal-to-noise ratio is the ratio of the peak-to-peak signals of the ASME hole and of the ID noise as shown in the lissajous patterns using the primary frequency of 550 kHz. The results are presented in Table V.B.3.

These values can be compared with summary of drawn and pilgered tubing examined by EPRI (see Table V.B.2). As shown in Table V.B.3, the Unit 2 steam generators have S/N ratios that are below the EPRI and Laborelec recommended minimum values. Since the tabulated values are averages, an indeterminate number of tubes in the Unit 2 generators exist with S/N less than 2.9:1. Therefore, minimizing tube noise effects is important for the pilgered tubing installed in the Unit 2 steam generators.

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

2. Eddy Current Detectability (cont.)

- Noise Level Effects (cont.)

  - PVNGS Eddy Current (ECT) Program:

    Improvements in eddy current technology have provided analysts with the tools necessary to reduce the effects of pilgering noise. Screening for defects at PVNGS is accomplished by using a frequency mix (P1 550-100 kHz) to eliminate the effects of support plates and permit evaluation of signals present in the vertical plane. Pilgering noise is effectively managed at PVNGS by adjusting the detection/screening display such that the noise signals are in the horizontal plane (see Figure V.B.8). The ASME standard and tubing flaws and degradation are displayed in vertical presentations (see Figures V.B.9 through V.B.11). It should be noted, that while horizontal noise in Unit 2 is nearly five times that of drawn tubing, in most cases the vertical noise is approximately the same magnitude as values as given for drawn tubing.

    The low S/N ratios observed in the Unit 2 steam generators are below the levels recommended by EPRI, Laborelec and Valinox for reliable defect measurement. However, the S/N values are adequate to defect detection. Since all tubing with suspected cracks are verified by MRPC and are removed from service, crack sizing is not considered a requirement, and therefore cracks are typically classified with three letter codes such as SAI and MAI. The MRPC probe surface riding capability reduces lift-off as an extraneous test variable and is therefore less affected by ID surface variations.

    In summary the PVNGS eddy current program minimizes the effect of pilgering noise by:

    - Presenting pilgering noise horizontally and screening defects using a vertical presentation. Vertical noise is not considered high at PVNGS.

    - Confirming crack screening with MRPC to eliminate impact of tube noise.

    - Not using voltage amplitude threshold criteria or attempting to size axial indications with the bobbin coil screening for determination of repairable defects.

B. ECT METHODOLOGY AND DETECTABILITY REVIEW (cont.)

2. Eddy Current Detectability (cont.)

During the U2R4 inspection approximately 22,000 tubes were inspected full length with bobbin coil ECT. A extensive quantity of support intersections and feet of freespan locations were also inspected with MRPC. The MRPC inspection detected a number of indications which were classified by APS as NBI. The NBI designation was assigned to eddy current indications which would not "normally" be reported by the primary and secondary analysts given the training and guidelines provided at the beginning of the U2R4 inspections. However, upon re-review of bobbin signals, with support of the MRPC for location, a small discontinuity in the signal could be detected for a number of these tubes. An evaluation of these locations was conducted to determine if pilgering noise could be "masking" defects. In Tables V.B.4 and V.B.5, a summary of noise levels and defect signal strength in tubes with confirmed axial indications were identified. The average horizontal and vertical noise amplitudes in SG 21 were 1.59 and 0.13 volts respectively. Similarly, in SG 22 the noise strength was 1.74 volts horizontal and 0.13 volts vertical.

Voltage signals associated with NBI, NQI and bobbin detected defects were identified, and a signal to noise ratio was calculated. Additionally, ASME standard S/N ratios as high as 17.1:1, well in excess of the EPRI detectability recommendations, were calculated for some of the affected tubes adjacent to the NBI indication. Therefore, it has been concluded that the defect orientation and characterization is the principle cause of the detectability problems associated with these flaws and not the presence of high pilgering noise.

The pilgering noise in the Unit 2 steam generators is higher than industry recommendations; however, the tube noise is not considered to be a significant defect detectability issue. APS repairs all crack defects regardless of size, and therefore, the S/N ratios recommended by EPRI for defect sizing with bobbin coil techniques do not apply. These conclusions have been discussed and concurred with by industry consultants from EPRI and CONAM.

C. TUBE PULLING

Prior to the rupture tube, tube pulls were scheduled for U2R4 to evaluate the cause for 01H support (flow distribution plate) axial cracking previously identified in U2R2. In order to determine the root cause of the ruptured tube and evaluate the additionally identified axial indications in the upper bundle, a tube pull selection criteria was developed. The criteria is tabulated in Table V.C.1. As part of the selection process and in conjunction with the criteria, the tube pull candidates were categorized into four categories: tubes with flaws at 01H, tubes with freespan flaws, tubes with flaws of upper bundles supports and clean tubes.

- **Tubes Selected**

Starting with the list of all tubes with axial indications, each tube was evaluated to determine which tube(s) would provide the most information within the identified categories. The steam generator inspection process included a 100% bobbin examination with selected tubes inspected by MRPC. There were tubes where the bobbin inspection did not record an indication but with the MRPC an axial defect was identified. To evaluate that discrepancy, two tubes were selected which met that condition.

Also, tubes were evaluated based on their position relative to other tubes with axial indications, including axial deposits. (Refer to Section V.E Orientation Testing for relative location of pulled tubes to adjacent tubes with indications at similar elevations.) In addition, tubes were chosen to represent different regions of the tube bundle. As a contingency, extra tubes were selected as backup candidates.

Table V.C.1 lists the primary and secondary tube pull candidates and the basis for selection. A brief summary of the basis for selection is provided below. Figure V.C.1 shows the areas of the tubesheet where tube sections were removed.

a. Tubes with Flaws at 01H: (R22C13 and R29C24)

In the 1993 inspection, three tubes were identified with axial indications at the 01H. One tube exhibited significant growth from the 1991 inspection results. In addition to that tube, a second tube, one which contained an axial indication (recorded by MRPC) which the bobbin reported as a DSI was selected.

b. Tubes with Mid-span Flaws

- Rupture Tube and Large Through-Wall Flaw (R117C144 and R105C156)

The tube rupture occurred freespan below the 09H. In addition to the ruptured tube, a second tube with a freespan flaw comparable to the rupture, was selected.

C. TUBE PULLING (cont.)

- **Tubes Selected (cont.)**

b. Tubes with Mid-span Flaws (cont.)

- Axial Flaw detected by MRPC but not Bobbin (R103C156 and R117C40)

  Two tubes were selected which contained freespan axial indications detected by MRPC but not by bobbin coil eddy current inspection. Both indications were recorded between the 08H and 09H.

c. Tubes with Flaws at Supports (07H, 08H, or 09H) (R127C140)

In addition to the recorded axial indications at mid-span, some axial indications were found at upper bundle supports. One tube which contained an axial indication at both the 07H and 08H was selected for removal to evaluate this type of degradation.

d. "Clean" Tube (R116C41)

In order to evaluate the detectability limits of eddy current, one tube, which had no indications identified between the 08H and 09H support, was selected. An additional criteria for this tube was that it would be located next to tube(s) with recorded axial flaws.

e. Process

A total of eight tubes were pulled for the metallurgical analysis. Final tube pull candidates are listed in Table V.C.2. Tube pulling was performed using the following process:

- Clean the tube by honing the expanded region in the tubesheet.
- TIG relax the expanded region in the tubesheet.
- Remove the tube to tubesheet weld.
- Perform load deflection test (verify tube is not "locked" at a support or at tubesheet).
- Whip cut the tube at an elevation above the area of interest.
- Verify the cut by video probe.

C. TUBE PULLING (cont.)

- **Tubes Selected (cont.)**

  e. Process (cont.)

  - Pull the tube using ID collects, spacers and double block clamps.
  - Section the tube in SG bowl as necessary to facilitate removal.
  - Perform ECT of the pulled tube sections (following removal).
  - Prepare tube sections for shipment.

  A sectioning drawing for each tube removal is shown in Figures V.C.2 through V.C.9.

D. VIDEO ANALYSIS

Following the removal of the tube pull candidates, a secondary side video inspection was performed of the surrounding tubes. A video record was made by moving a remote camera through the full length of the channel created by the pulled tube. In order to assure areas of special interest received a detailed inspection, a check list was prepared as shown on Table V.D.1. The objectives of this inspection were to evaluate potential tube OD conditions such as flaws and deposits, as well as any abnormal tube bundle physical configurations. Evidence of reduced tube spacing and tube bowing was observed (see Figure V.D, pictures 1 through 8 from Video Inspection) for tubes remaining in the generator as well as the tubes removed via the tube pull operation.

1. Bridging/Ridge Deposits

The following video tapes were recorded. Note that the tube numbers listed denote the positions where the video probe was located (i.e., not the tubes inspected).

Row-Column (Date)
R22C13 and R29C24 (5-29-93)
R116C41 (5-7-93)
R116C41 (5-17-93)
R103C156 (5-15-93)
R105C156 (5-13-93)
R117C40 (5-8-93)
R117C144 (5-19-93)
R127C140 (5-13-93)

A detailed review was performed of the secondary side video recorded during the tube pull operation. Observations on areas identified as reduced tube gap, deposit bridging, blockage at the 01H and whip cut offsets is provided below. From the review of those tapes it was determined that the following had a less-than-nominal gap between them.

- **R117C40 and R115C40 (See Figure V.D Pictures 1 and 2)**

  Tubes R117C40 and R115C40 taper toward each other when moving up past the 08H tube support. It appeared that they were in contact or bridged by deposits through a small gap between them beginning at approximately 26 inches above the 08H support. One or both of these tubes had obviously bowed.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

D. VIDEO ANALYSIS (cont.)

1. Bridging/Ridge Deposits (cont.)

- **R117C42 and R115C42 (See Figure V.D Pictures 3 and 4)**

  Tubes R117C42 and R115C42 also tapered toward each other when moving up above the 08H tube support. It appeared that they were in contact or bridged by deposits through a small gap between them beginning at approximately 30 inches above the 08H support. Again, it appeared that one or both of those tubes were bowed.

- **R103C156 and R102C155**

  Tubes R103C156 and R102C155 also showed bridging due to a less-than-nominal gap between them. The bridging was seen between the 07H and 08H supports (starting at approximately 10 inches above the 07H and ending approximately 28 inches above the 07H) as well as above the 08H (starting at approximately 4 inches above the 08H and ending at approximately 18 inches above the 08H).

After reviewing several tubes with deposits the following tubes appeared to have deposits that were bridged to the pulled tubes:

- **R115C144 bridged to R117C144 (pulled)**

  Both of those tubes had thick deposits remaining on them with a flat spot where they had been connected to the neighboring tube. Both of those deposits were above the 08H. Deposits on R115C144 started at approximately 28 inches above the 08H and ended at approximately 37 inches above the 08H.

- **R104C157 bridged to R105C156 (pulled) (See Figure V.D Pictures 5 and 6)**

  Deposits on R104C157 started at approximately 12 inches above the 08H and ended at approximately 24 inches above the 08H.

  In order to validate the video analysis, a mock-up of the upper bundle tube configuration was made. Nominal tube gaps were inspected with the video probe to develop a bench mark. Next a simulation of what appears to be a severally bent tube (R103C156) was inspected (the inspection in the SG was made from tube position R105C156). Comparison of this test with the actual video footage confirmed that tube R103C156 was severely bent.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

D. VIDEO ANALYSIS (cont.)

2. Tube Separation After Whip Cut

A video inspection was performed after the whip cut in the tube pulling process to verify a complete 360 degree tube separation. This inspection was performed by moving a remote camera from the primary side to the elevation of the cut. The video data from each whip cut was reanalyzed to determine if tube ends after cutting were misaligned, which would indicate side loading on the tube.

A review was performed of video tapes made during the tube pull whip cut confirmation in which a remote camera was inserted from the primary side tube end to the elevation of the whip cut. Two different camera lens configurations were used. Three tubes were inspected using a straight lens in which the bottom section of cut tube can be seen in conjunction with the upper section in the background. One tube R22C13 did not appear to have an offset, but tubes R103C156 and R117C144 appeared to have an offset between the cut tube ends.

Mock-up testing was also performed to simulate primary side video inspections of whip cuts. This test clearly showed tube offsets observed in the field can be easily identified on video.

3. Flow Distribution Plate (01H)

Flow distribution plate (01H) crevices inspected appeared to be either blocked or partially blocked. Most areas inspected also contained spalled-off deposits laying on top of the 01H as well as apparent loose flake-like debris. (See similar flake-type deposits in Figure V.D Pictures 7 and 8.)

E. ORIENTATION TESTING

Based on the primary side video inspection of the leaking tube, the rupture was a "fishmouth" opening orientated along the tube axis. Subsequent MRPC inspection also recorded the rupture and defects on other tubes as an axial flaws. In addition MRPC also recorded indications at low frequency (20 KHz) which in some cases were aligned with axial flaws and in some cases occurring without flaws. The low frequency indications were classified as deposits on the tubes' outside diameter. These flaws and deposits were located both at and between support structures. It was determined that the orientation of the axial indications relative to the tube bundle was needed to evaluate potential damage mechanism.

1. Test Description

In order to determine the orientation of a tube's flaws and/or deposits, a special inspection technique consisting of a MIR probe was used. The reference angle of the flaw/deposit is found by inserting the MIR probe into a tube adjacent to a target tube. The target tube is then inspected by the MRPC.

The magnetic field generated by the high energy magnets located in the MIR provides a reference in the MRPC signal. In order to avoid distorting the flaw/deposit, the MIR probe is positioned below the area of interest in the target tube. The MRPC probe is then positioned above the area of interest and withdrawn past both the flaw/deposit and MIR probe as the data is being recorded. By knowing the relative position of the tube with the MIR probe and the target tube, which was inspected by MRPC, the orientation of the flaw/deposit can be identified.

2. Results/Conclusions

A total of 31 tubes in SG 21 were inspected using the MIR probe orientation technique. Tube R105C156 was examined twice with the MIR probe located in two different adjacent tube positions. This provided confirmation that the MRPC probe was rotating in the clockwise direction (looking up at the tubesheet). All other tubes were inspected by MRPC with the MIR probe in one adjacent tube.

The tubes inspected and basis for their selection is provided in Table V.E.1. Figures V.E.1 through V.E.9 show the tubes inspected and the relative orientation of flaws/ deposits.

E. ORIENTATION TESTING (cont.)

2. Results/Conclusions (cont.)

- Axial Indications

Axial mid-span deposit indications (some concurrent with axial flaws) appeared to occur in pairs with the indications facing one another. In almost all cases the pairs of indications were in the same (tube) column. This relationship included the ruptured tube (R117C144) and an adjacent column tube (R115C144).

Axial indications at supports did not have any apparent orientation pattern.

- Wear Indications

The wear indications tested at the 08H and 09H supports were oriented toward the bundle periphery (i.e., away from the divider plate). One BW1 wear indication tested was oriented toward a batwing strip.

Subsequent to the flaw/deposit orientation work with the MIR probe, additional axial indications were recorded in both SG's. In order to evaluate the orientation of the additional indications, a reanalysis technique was developed which provided a qualitative method of assessing the direction the flaws/deposits were facing. This technique used the batwing signal (MRPC) as a reference to the orientation of an indication. Using this method, an indication can be evaluated to be facing either along tube rows (in the relative direction of a batwing signal) or along tube columns. This study identified that axial mid-span flaws and deposits were predominantly oriented along tube columns. Further information on this work is contained in the "Deposit Formation" section of this report (V.P).

F. DESIGN/FABRICATION REVIEW AND RESULTS

The APS task force set out to define possible cause(s) for the seemingly advanced tube degradation in Unit 2. Among the possible causes identified was the shop fabrication, particularly as it related to the tube support assembly and the tubing operation.

A review of ABB/CE's fabrication methods and their records relating to the fabrication of the SG's was performed. The purpose of the review was to determine if a link existed between the initial fabrication and the observed failures. The design history/evolution of the U-tube support structure was also reviewed.

The review process included discussions with some of the personnel who were involved in the design and fabrication of the SG's.

Special emphasis was given to the evaluation of the tubing manufacture, the tube bending operation and the tube installation into the steam generators.

The results of the review for the Unit 2 SG's revealed no unusual fabrication problems. All deviations and irregularities that could be identified can be classified as typical occurrences. The deviations, as will be summarized next, could have been found in any fabrication shop engaged in similar activities.

1. Tubing Manufacture

All tubing was produced by the pilgering process by the same tube mill and to the same specifications. The only major difference in the manufacturing process for the tubing between Units 1 and 2 was in the acceptance criteria for the Eddy Current Test from the ID for noise level. The acceptance criteria for Unit 1 rejected all tubes whose average horizontal indication exceeded 400 millivolts and/or vertical indication exceeded 100 millivolts, while the criteria for Unit 2 was 800 millivolts and 150 millivolts respectively.

2. Tube Bending

The tubing supplier furnished CE tubes which were already bent for Unit 1, whereas, Unit 2 tubing was furnished straight and tube bending was performed by Combustion Engineering. The bending process by CE for nuclear steam generators began in late 1977 on units for other utilities. Tube bending for Palo Verde Unit 2 began in mid-1978. This process required samples to be bent and furnished to CE for evaluation before beginning the production. Evaluation of the bending process was perrormed to the same criteria by CE for both units (SG 21 and SG 22). The tube bending records did not reveal any problem with the in-house tube bending process.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

3. Tubing Operation

Deviations from engineering requirements were documented in rejection notices. Rejection notices dealt mainly with scratches on tubes and nail indentation. All tubes that were identified with scratches were polished to remove the scratches. The tubes identified with dents from nails were replaced. Tubes that had rejected conditions due to tubing process that could not be removed and replaced were plugged.

In addition, logs were kept in the tubing room while the steam generators were being tubed. The purpose of these logs were to identify problem areas and status the tubing progress.

At the end of the log for SG 22, the 3rd shift noted on August 23, 1978 that there were two tubes which were extremely hard to install. These tubes would have been in row 116 or row 117. This is established based on the notation that 49 tubes were installed in row 116, and 21 tubes were installed in row 117 for that shift. The record search did not reveal anything that would enable us to identify these two tubes by specific row number and/or line number.

The search of the engineering records did not reveal any additional problems over and above those documented in the rejection notices.

Additionally, the shop foreman responsible for the tubing operation was interviewed. He could not recall anything about SG 22 that was significantly different from the other units, and that all units were about the same from the fabrication standpoint.

4. Steam Generator Fabrication Following Tubing

All steam generators go through the same basic fabrication steps following the tubing operation. There was nc indication that anything unusual occurred in this phase of fabrication for Unit 2 SG 22.

5. Engineering Records

There were no significant findings in the engineering records. A detailed record search did not reveal any significant differences between Unit 2 SG 22, and any other Palo Verde steam generator.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

6. Potential Manufacturing Problems with the System 80 Steam Generators

The purpose of this section is to postulate problems during fabrication or methods in manufacturing that were not formally documented. These could be random occurrences in methods or techniques of assembly or simply problems that seemed inconsequential at the time, but now may have a part in influencing the overall scenario.

- Scratches

  Scratches that occur between eggcrate supports can be readily accepted as a random occurrence of significant probability if the scratch is in the axial direction, matches a circumferential orientation that would put it in contact with the edge of the eggcrate above as the tube was being inserted, and is below one of the horizontal eggcrates (i.e., 09 support or lower). A deep scratch with a very narrow width could be the result of a burr on the edge of the eggcrate that was missed during the deburring operation of the eggcrate strips before assembly. A shallow scratch with little depth but very wide is called a manufacturing burnish mark (i.e., a scuff mark). Burnish marks could be the result of either a tube being inserted in a direction that is not parallel with the other tubes or a tube being inserted through the diamond pattern of an eggcrate that has been distorted elliptically. As the tube is forced passed either of these situations, the edge of the eggcrate scuffs the tube OD.

Another scenario for burnishing marks could be postulated for the tubes near the scallop bar in Rows 64, 65, 114, and 115. This scenario could occur when the edge of the adjacent outer tube (that is next to the scallop bar) scuffs the inner tube (i.e., tube 66 onto 64, tube 67 onto 65, tube 116 onto 114, tube 117 onto 115). The precursor for this event is that the tube next to the scallop bar cannot be inserted through the scallop bar easily. Note that the scallop bar is the first "support" the tubes 115 through 117 encounter when being inserted. Considering the reduced gap and difficulty for insertion, the tube would tend to approach the neighbor tube at an angle. Using the scallop bar as a lever, the edge of the tube would scrape along the adjacent tube until it jammed or its alignment was corrected. This could produce burnish marks on the tubes in rows 64, 65, 114, and 115 that faced in the column direction towards the scallop bar. The tubes in rows 155 through 117 could also be marked from contact with the scallop bar in the same direction.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

6. Potential Manufacturing Problems with the System 80 Steam Generators (cont.)

- Tube Bowing

  A scenario that could cause a SG tube to bow would be if the vertical support grids were applying an abnormal load to the horizontal section of the tube. The vertical support grid region is basically an eggcrate support that is perpendicular to the full and partial eggcrate supports below. However, to manufacture the same diamond pattern of the full and partial eggcrates in the vertical support grid region is unreasonable. Thus, the vertical support grid region uses a square eggcrate design with tubes in every other square. This increases tube spacing from 1 inch in the diamond pattern of the lower eggcrates to 1.75 inch in the vertical support grid region and increases the gap between the tubes from 0.25 inch in the lower eggcrates to 1 inch in the vertical support grid region. During fabrication, the SG tubes are inserted horizontally, the plane of the tubes being parallel with the ground (i.e., the divider plate is perpendicular to the ground). The ventilated vertical straps (VS's) lay one on top of each other and the horizontal top part of the tube is slid between each strap. This forms two parallel sides of the square eggcrate. Horizontal strips are then inserted into the slots cut into the VS's. A slotted lock bar is installed for a horizontal strip every tenth space to assure proper spacing of the vertical strips. After a row is inserted, all of the horizontal strips are put in place and tack welded to the VS. The horizontal strips are staggered from one side of the VS to the other.

Thus, the other two parallel sides of the square eggcrate do not face each other (i.e., each horizontal strip is only half as wide as the VS and do not form a complete square around the tube). If the horizontal strip did not go into its slot easily, the horizontal section of the tube could be pushed inward (i.e., towards the tubesheet) so that the horizontal strip could be inserted. Since there is no horizontal strip directly behind the tube in this scenario and the tube-to-tube spacing is 1 inch, this would preload this horizontal section of the tube in the downward direction. The more force used to insert the horizontal strip, the higher the preload on the tube. As the tube went from a cold state to operating temperatures and pressures, the operating stresses could translate these preload forces to the section of the tube between the BW and the 09 support in the form of deflection, causing the tube to bow outward in the column direction.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

6. Potential Manufacturing Problems with the System 80 Steam Generators (cont.)

There is supporting evidence of this possible scenario occurring in the Unit 2 SG's during fabrication. However, it is anticipated that this would be a localized or randomly scattered occurrence of small magnitude. The calculations in a recent 3-D tube bundle analysis show that if the tube in Row 117 was deflected downward by ~ 0.035 inch in the cold condition, then it will bow ~ 0.019 inch outward which is nearly the nominal tube spacing in the horizontal direction. Also, a similar scenario using this ratio, can be developed between two adjacent tubes (in the column direction) where one is preloaded downward by ~ 0.24 inch and the other is preloaded upward by 0.19 inch. This would result in the tubes bowing towards each other, each by 0.13 inch which also spans the 0.25 inch gap between the tubes.

During ideal design conditions, this scenario should not be possible, as all of the tubes would have ideal insertion and perfect spacing in accordance with the design geometry. Indeed, from the information available, the vast majority of the 22,000 tubes in the Unit 2 SG's were installed correctly with no trouble inserting the horizontal strip. However, given the condition that some of the tubes may have experienced these problems, the next subject would be how this condition is possible. Considering the assembly techniques and the design of the VS region, any of the following parameters could influence this condition.

a. The vertical straps (VS's) were not fabricated in the Chattanooga facility. They were manufactured at the CE St. Louis facility on a tape controlled punch press. The VS's were not cut then inserted individually into the punch press. Instead, the punch press punched out the pattern on a sheet of steel first, then the VS's were cut out individually later. The pattern was controlled by the computer "tape" which used a die with multiple ventilated holes and slots (~6) to punch out the majority of the pattern. However, another die with a single elliptical hole and slot was then required to finish the pattern where the pattern was not adaptable to the multiple die. If the indexing was off on the single die, some of the slots between these groups of six would be out of alignment. Such scenarios in repetitive punching operations can occur and not be readily identified.

b. The tack welding slightly bowed the horizontal strip. If the tube was already tight against the tube, then this may increase the preload.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

- **Potential Manufacturing Problems with the System 80 Steam Generators (cont.)**

c. The tube lengths were cut on a template table after bending. The bent tube had to fit the template before cutting. If a templates is set incorrectly such that the tube is too long, this would make the horizontal strip difficult to insert. Since each row is identical dimensionally and unique from the other rows, each row requires its "own" template. However, if a template was incorrect dimensionally, it would be expected the whole row of tubes using this template would exhibit this problem.

Tube bowing may be a direct result of one or a combination of the preceding factors.

- Transportability

It must be assumed that small similar deviations could occur in all three units. However, if the preloading of the horizontal section of the tube is an off-design condition, then it could also manifest itself in other areas as wear. The magnitude or number of tubes affected would also be in direct proportion to the amount of wear in each SG. Using this line of reasoning, then the Unit 2 SG's exhibit this condition to a much greater degree than the other two units, with Unit 2 SG 22 to a greater degree than SG 21.

7. Tube Bowing and Buckling Studies

Studies of the potential for the tubes to buckle, bow, and ratchet were conducted to evaluate the possibility that the defects and deposits found on tubes in the upper bundle region were a result of the tubes moving closer together. The scenarios hypothesized by various parties included distortion during initial fabrication, gross binding of the tube bundle at the I-beam supports, vertical binding of individual tubes at the batwings, and lateral binding of individual tubes in the vertical supports. Finite element models were used to analyze the tubes for buckling instability and large deformation theory bowing. The results of the analytical studies were combined with information obtained from fabrication records research and SG 22. The analytical studies are described as follows:

- Buckling Instability Studies

Several of the loadings hypothesized would have the potential to load the tubes axially. This type loading could result in tube buckling instability and subsequently cause a large lateral deformations which could close the 0.25 inch gap between tubes. Therefore, a buckling analyses was performed on the tube that ruptured during operation to determine the load required for instability to occur. These loads were compared to potential loads which might have occurred during fabrication and operation under normal and abnormal conditions.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

7. Tube Bowing and Buckling Studies (cont.)

- Buckling Instability Studies (cont.)

The straight tube model was first analyzed and compared to classical buckling theory as a validation of the model and analytical technique. The instability load was determined to be 570 lbs. This compares exactly with classical buckling theory.

The U-bend model was analyzed to determine the effect of the U-bend and the vertical supports on the instability load. The instability load was determined to be 1640 lbs. This shows that the true buckling load is much higher than simple column theory.

Both cases show the instability load to be higher than loads which could be postulated. Analyses reported elsewhere show that if there was gross binding by the I-beams, the axial force on the tube would be only 142 lbs. Fabrication records show no general use of high forces to install the tubes and it is inconceivable that the load would have been over 1604 lbs. since this is a "one man" operation per tube leg. Therefore, it can be concluded that buckling instability and resulting closure of the gap is highly improbable.

- Large Deformation Bowing Studies

In similar fashion even if the loadings were not severe enough to produce buckling of the tubes, it was postulated that deformations sufficient to narrow or close the gap between tubes during operation might result due to axial loadings on the tubes. Large deformation theory and finite element analyses were performed to determine hypothetical lateral deformations for postulated vertical thermal deformation loadings.

Finite element models of tube row 117 were used to conduct the analyses. Two basic models were used, a straight tube model and a U-bend model. These are shown in Figures V.F.1. and V.F.2 respectively. The straight tube model represents the tube span between eggcrate 8H and the batwing. The model is actually a half-span model to facilitate boundary conditions (i.e., full support at mid-span and simple support at the batwing). The U-bend model represents the hot side of the complete tube. The eggcrates and vertical supports are modeled as simple supports with full support at the tubesheet. In both models, eggcrate 9H is assumed to be inactive since it only supports one side of the tube.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

7. Tube Bowing and Buckling Studies (cont.)

- Large Deformation Bowing Studies (cont.)

The gross thermal expansion of the tube bundle relative to the I-beam is 0.146 inch. Two cases were analyzed for the vertical deformation that would be imposed if the I-beam restraint is imposed on the tubes by the support at VS3. Deformation plots from the finite element analyses for these cases are shown in Figures V.F.3 and V.F.4. Case 1 assumed the tube does not experience sidesway (i.e., the vertical supports prevent sliding laterally and the tube deforms symmetrically with respect to the steam generator centerline). The lateral deformation produced by this axial deformation is 0.067 inch. Case 2 assumed the tube is free to move about the steam generator centerline (i.e., the vertical supports allow sliding laterally). The lateral deformation produced by this axial deformation is 0.267 inch).

The actual support behavior is difficult to absolutely define. Although the vertical supports were designed to allow lateral motion, it is conceivable that the vertical motion would result in binding that would prevent or restrict sidesway. However, previous inspections show wear at the vertical supports indicating that lateral movement of some amount had occurred. Thus, it is concluded that gross binding of the tube bundle at the I-beams could produce lateral tube deformations of sufficient amount to narrow and, in fact, close the gap between tubes. However, as determined by the SG 22 inspections during the 2R4 outage and previous outages, there was no evidence that such binding was occurring.

The tube expands vertically 0.218 inch more than the batwing. This condition was analyzed and evaluated elsewhere. Total restraint of this deformation produces large axial and bending loads above those required to yield the tube and the batwings. Since the inspection at this outage did not reveal this type of structural failure, the possibility of large lateral deformations due to batwing tube vertical lockup is discounted.

The other scenario that was postulated which could narrow the gap between tube is thermal ratcheting. The tubes experience more lateral thermal growth than the batwings. If individual tubes bind at a vertical support or batwing during heatup or cooldown, relative motion could occur between adjacent tubes. As reported elsewhere, the relative lateral motion of tube row 117 and the batwing is 0.032 inch; therefore, the gap could close by this amount during a single cycle and could experience ratcheting closure motions of the same magnitude through a slip-stick mechanism during subsequent operational cycles.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

7. Tube Bowing and Buckling Studies (cont.)

- Summary

(1) Tube bowing can be considered as abnormal elastic movement of the tube during heatup which moves a tube closer to its neighboring tube only during power operation. When cooled back to room temperature, the tube returns to the original 0.25 inch spacing. Factors that could cause this bowing are:

(a) Preloading of the horizontal section of the tube during fabrication from either bent horizontal strip mislocation of the locking slots, or vertical tube length is too long when installed. None of these factors are confirmable without destructive testing.

(b) Binding of the I-beam support in their slots that prevents upward movement when the bundle is thermally expanding. As stated in the Fabrication Review, there is no visual evidence of such binding or restraint.

(2) Tube buckling can be considered an instability that deforms the tube, leaving the vertical run of tubing permanently bowed towards or into an adjacent tube even when cooled to room temperature. From the Fabrication Review, factors that could cause this bowing are:

(a) Thermal ratcheting of the tubes from corrosion lockup/increased friction in the BW area. The greater the friction, the greater the distance the tube ratchets, up to 0.032 inch during each heatup/cooldown cycle.

(b) Preloading of the horizontal section of the tube during fabrication with a force of ~1600 lbs. This type of loading is much higher than that postulated in (1)(a) and is considered to be unlikely for the multiple tubes in question.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

8. The Design Evolution of the System 80 Steam Generator Support Structure

The steam generators at PVNGS are of the System 80 design and were manufactured by ABB/CE (CE) at the Chattanooga, TN facility during the late 1970's. The design of the System 80 SG internal tube bundle support structure evolved from the earlier SG's that CE designed, manufactured and sold to the various electric power utilities during the 1960's and 1970's. Tube supports are required at periodic intervals along the U-tube to prevent flow induced vibration which can result in fretting wear and/or fatigue failure. The changes to the design from the earlier units were basically a result of trying to balance two opposing design parameters:

a. The desire to maintain a large number of supports and their associated rigidity to provide the large margin (i.e., the "over-design" margin) for operating loads (mechanical stresses and flow induced vibration) and accident loads (i.e., LOCA, MSLB); verses

b. The empirical evidence from the operating units that showed that the higher the number of supports, the more crevices are created in which corrosion products will accumulate, resulting in more plugged tubes.

The area in which there was the most "change" in the design of supports in the history of the CE SG's was in the upper bundle region, namely the partial eggcrates, the batwings and the vertical support grids. The following outline details this design evolution.

a. The "Early Units" consisted of Palisades, Mihama-1 (Westinghouse), and Fort Calhoun. The overall design of these SG's are too varied to be able to be grouped into any specific category. However, they did have one common feature in that the eggcrate design of their VS region was such that they used scallop bars to lock in the horizontal span of the tubes.

   (The VS region is basically an eggcrate support that lays on its side, with respect to the full and partial eggcrate supports below. However, to manufacture the same diamond pattern of the full and partial eggcrates in the VS region is unreasonable. Thus, the VS region uses a square eggcrate design with tubes in every other square. This increases tube spacing from 1 inch in the diamond pattern of the lower eggcrates to 1.25 inches in the VS region of the Early Units which aided manufacturing [and aided Engineering by allowing the fluid to exit the bundle with less resistance]. However, the tubes in the VS region were still close enough that a straight locking bar could not be used to lock the tube into its square eggcrate during assembly. A scalloped shaped locking bar was used.)

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

8. The Design Evolution of the System 80 Steam Generator Support Structure (cont.)

Note: When comparing fossil boilers to nuclear SG's, the SG's were "unique" in that the boiling takes place on the shell side as opposed to the tube side. So, very little flow-induced vibration data was available to the designers of the CE SG's. Hence, to ensure the absence of flow induced vibration, the tube support structure in the early units were over-designed from a vibration standpoint. The opposing effect of this over-designing was that the supports were partially shielding the tubes, potentially resulting in flow starved regions were deposits could concentrate.

b. The first group of plants that had a common design were called the Series 67 or the ~2800 MWt units. This category consists of Maine Yankee, Calvert Cliffs-1 and 2, St. Lucie-1, and Millstone-2.

The Series 67 upper bundle design (see Figure V.F.5) consisted of four partial supports and a unibody design of the BW's and VS's. This unibody design meant that the VS's and BW's were welded together as one piece before being installed in the SG. The VS and BW material of the unibody was carbon steel. The width of each BW and VS was 4 inches. The BW's laid across the tubes directly over the bend radius and came together at a point to form a "V" design. The bottom of this "V" was tied directly to the topmost full eggcrate support. The VS's were not ventilated (i.e., did not have elliptical flow holes).

The four partial supports consisted of two diamond pattern eggcrates below and two drilled plates above. The top two partial supports were designed as drilled plates to provide a large amount of rigidity in the upper bundle (i.e., a very conservative design which has large margin of allowable stress).

The major change from the early design to the Series 67 design was that spacing of the tubes in the VS region increased from 1.25 inch to the 1.75 inch that it is today. This eliminated the use of the scalloped shape for the locking bars on the VS's (except for Maine Yankee which has the scalloped bar design). The reason for this change was that it was observed in the field that the scalloped shape locking bars were acting as crud traps. The flat locking bar has much less crevice area than that of the half-moon shoe of the scallop bar. This change can be deemed important as it was the first acknowledgment that crevices were undesirable (from either a corrosion or denting standpoint).

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

8. The Design Evolution of the System 80 Steam Generator Support Structure (cont.)

c. The next group of plants that had a common design were called the 3410 Series or the 3410 MWt units. This category consists of ANO-2, Jersey Central (cancelled), SONGS-2 and 3, Waterford-2, St. Lucie-2.

The 3410 Series upper bundle design (see Figure V.F.10, Figure V.F.6 - cancelled) consisted of the three partial eggcrates (PE's) and a segmented design of the BW's and VS's. This segmented design means that the VS's and BW's are not joined together as one piece. The BW's were still one long piece, but the VS's were now each a single strip of carbon steel which leaves a gap between the BW and VS when viewed from the side. The width of each BW and VS was reduced to 2 inches. The BW's were moved lower so that it would no longer lay across the bend radius of the tubes. For this reason, the bottom of the BW's no longer could come together at a point to form a "V" design, since the point of the "V" would be too low in the bundle. Thus, the BW's now had a horizontal strip at the bottom called the dogleg. The VS's were now ventilated (i.e., elliptical flow holes punched through them for flow) (see Figure V.F.7). The three PE's were all of the diamond pattern eggcrates design (i.e., no drilled plates). (Note that ANO-2 was a hybrid of the Series 67 and the 3410 Series designs. The unibody design was maintained, but the BW/VS unibody was raised higher to move the BW above the bend radius of the tubes (see Figure V.F.8). The width of the BW's and VS's was reduced to 2 inches, but the VS's were not ventilated. There were four PE's of the same design as the Series 67. Also, note that the MWt rating of ANO-2 was <3410 MWt and St. Lucie-2 was ~2800 MWt.)

The driving force behind this design change was corrosion. The direction for the design of the 3410 Series was to minimize crevices/corrosion sites that became evident in the Series 67 units (and was an important issue for the industry in general at the time, as it is today). Thus:

(1) It is noted that in the bend radius of a tube, the tube is oval from the 90 degree bend. This ovality puts the tube closer to the BW, causing a tight crevice. So, the BW's are moved lower, out of the bend radius, to increase the width of this crevice. This changes the "V" design and introduces the dogleg.

(2) It is noted that the VS's in a unibody design must lay across a bend radius for some of the tubes. So, the VS's are disconnected from the BW's, creating the segmented design. Now, no VS lays across a bend radius of any tube.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

8. The Design Evolution of the System 80 Steam Generator Support Structure (cont.)

(3) The width of the VS's was reduced from 4 inches to 2 inches, thus eliminated 50% of the crevice length in the VS region.

(4) The VS's were ventilated to allow some cross flow to "wash" the crevice sites and to reduce the area of crevice sites in the VS region.

(5) The PE's were reduced in number from 4 to 3. This eliminated 25% of the crevice sites in the PE region. The design of the drilled plate was eliminated to eliminate the tight crevice sites in the PE region caused by the tolerances between the plate and the tubes.

Note: The changes to the tube support structure design are also made possible because of the increase in tube support vibration data becoming available. Dynamic coefficients made it possible to predict accurate flow forces. Test data was also yielding realistic damping values for use in tube stability analysis. The availability of high speed computers with sophisticated structural and thermal-hydraulic flow codes made it easier to not over-design the support structure and hence reduce areas with potential for flow starvation. However, the long lead time in SG materials and fabrication affects which units can benefit from the new design changes.

The result of these design changes in the 3410 Series is that the upper bundle now has more flexibility. Some of the design margin is used when comparing the 3410 Series to the Series 67 design; however, analytically the 3410 Series still is stable and conservative. Test data supported the analytical conclusions that the were acceptable margins against instability as a result of flow induced vibration.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

8. The Design Evolution of the System 80 Steam Generator Support Structure (cont.)

However, while the tubes of the upper bundle are analytically stable, it later became evident at SONGS that the new dogleg support portion of the BW is now subject to flow induced static deflection. Investigation at SONGS lead to the discovery of high flow velocities in the central cavity. The central cavity of the CE U-tube SG's is basically empty due to the stay cylinder design. During power operation, this region is subject to higher flows. The flat strip of the BW dogleg was subjected to high cross flows, which resulted in the static deformation (i.e., static out-of-plane bending which in some cases resulted in plastic deformation). As a sail tacks against a high wind, the horizontal dogleg was statically forced into the adjacent tubes next to the central cavity, resulting in wear. This required that the innermost tubes around the central cavity to be plugged on all of the 3410 Series units (up to 150 tubes in some cases). This became known in the industry as the BW wear problem/phenomenon. It should be noted that to date, this is the only inherent design problem with the 3410 Series upper bundle support design.

d. The next group of plants that have a common design were called the System 80 or the 3810 MWt units. This category consists of Palo Verde 1, 2, and 3, Yellow Creek(TVA)-1 and 2, WPPSS-3 and 5, Duke Power-1 through -6, Boston Edison Pilgrim-2, and the Palisades replacement SG's. Of these units, only Palo Verde (PVNGS) and Palisades are in operation; the others were cancelled. (Note that the Palisades replacement SG's were just placed in operation this year.)

The driving force behind the design change from the 3410 units was corrosion and manufacturing techniques:

(1) The number of PE's is reduced from 3 to 2. This eliminates 33% of the corrosion sites in the PE region (see Figure V.F.9).

(2) The BW and VS material was changed from carbon steel to 409-series stainless steel. All of the eggcrate material (full and PE's) was changed from carbon steel to 409-series stainless steel. This reduces the amount of surface oxidation so as to reduce the width of crevice sites throughout the entire bundle.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

8. The Design Evolution of the System 80 Steam Generator Support Structure (cont.)

(3) VS-2, -4 and -6 were shortened and allowed to be "free floating." This was changed to assist manufacturing and reduce the number of crevice sites in the VS region (see Figure V.F.10 and V.F.11).

The result of these design changes is that the System 80 upper bundle now has more flexibility when compared to the 3410 Series.

(4) The number of I-beam overhead supports was reduced from three to two. This was an attempt to ease fabrication and was considered to have no affect on normal operating conditions.

Note 1: It would be assumed that the batwing wear problem should have made itself evident during PVNGS power operation as the design of the BW is the same as the 3410 Series. (The BW wear problem became known after the System 80 SG's were manufactured.) However, other design changes (not related to the tube bundle supports) introduced an economizer section in the System 80 SG's. This design changes introduces a flow distribution plate in place of the 01 support and a lower economizer feedwater nozzle. These design modifications change the flow characteristics of the fluid in the central cavity such that the dogleg portion of the BW is no longer subject to flow induced wear.

Note 2: However, the economizer design of the System 80 was found to be subject to flow anomalies, not related to the design of the tube bundle support structure. The hotter downcomer recirculation flow is designed so as not to mix with the colder economizer flow entering the SG through the lower economizer nozzle. To keep the flow separated, a window was introduced in the tube shroud/wrapper plate above the economizer nozzle. The flow through this window was normal except near the divider plate where the tube lane between the innermost row of tubes and the divider plate was of lower flow resistance than the rest of the bundle. The lower resistance means high flow velocity which causes flow induced vibration for those corner tubes that were closest to the divider plate and the wrapper plate. This resulted in the plugging of some of these tubes.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

8. The Design Evolution of the System 80 Steam Generator Support Structure (cont.)

e. The latest group of units designed by CE are those for the Korean units currently under construction (i.e., Yangwong). The upper bundle support design from the System 80 was changed so as to incorporate the lessons learned from the System 80 and the 3410 units:

(1) The dogleg section of the BW was eliminated and the BW changed back to the original "V" design. This was to eliminate the concern of the BW wear problem that started at SONGS. As stated above, PVNGS does not exhibit this problem because of the economizer design. However, to be conservative, the Korean units were changed to be sure that the BW wear problem would be eliminated.

(2) When the BW is moved upward to form the "V," it was close enough to the VS's to be joined back to a unibody design. This meant that the concerns stated above were present again, namely the BW's and VS's would be located over the bend radius of the tubes. To compensate for the BW areas, the BW's were ventilated. For the remainder of VS's, it was deemed that this should not be such a concern as the VS's were also ventilated.

(3) When the BW was moved upward to reform the unibody design, a third PE was added.

(4) Note that the design of the downcomer recirculation window was also changed to eliminate the corner tube wear problem.

(5) The hot leg flow distribution plate is eliminated as it is deemed not to impact blowdown or flow stability.

This design is more rigid than the PVNGS design. However, the original compromise between rigidity and corrosion sites should mean that this design is slightly more subject to corrosion. Only when the on-line performance data is obtained can it be determined if this statement has any merit.

F. DESIGN/FABRICATION REVIEW AND RESULTS (cont.)

8. The Design Evolution of the System 80 Steam Generator Support Structure (cont.)

- Summary/Design Evolution

As described above, the history of design changes to the upper tube bundle support structure was driven by concerns over corrosion, ease in manufacturing, and small localized problem of flow induced vibration. When this evolution is viewed from an analytical perspective, the designs all meet the engineering requirements for a support structure in this application. The flow induced wear problems were the BW wear phenomenon in the 3410 Series and the corner tube wear problem of the System 80. In both cases, the wear was limited to a small localized area of < 100 tubes, which is < 1% of the tubes in the bundle. Such localized wear is considered to be unfortunate from a design standpoint but have no impact on the accuracy of the analytical model that justifies the overall design. These two cases of flow induced wear also occurred in the outermost row of tubes and can be deemed as interface problems with the surrounding structure and not indicative at all of what may happen to the center of the tube bundle, which is where tube R117C144 ruptured.

Additional analysis was also performed by CE (CENC-1950) in April, 1993, to investigate the contact forces of the upper bundle region. This study was a second verification of the loads in the upper bundle and the propensity to wear due to high contact forces or vibration. Loads were introduced axially on the horizontal tube runs during normal power operation in an attempt to induce vibration. The results show that the basic design of the upper bundle supports of the System 80 SG is sound. Thus, it can be safely assumed that the overall design of the System 80 SG is not subject to flow induced vibration.

However, this analysis did have a caveat that it assumes that all tubes are free to expand vertically. The possibility is thus suggested that a small handful of tubes may be abnormally restrained, such as would occur during improper assembly. This supposition is explored in the following section on manufacturing problems.

G. CONTACT FORCES

Analysis models were developed from design characteristics of the steam generator tube and tube support structures. A three dimensional finite element model of the tube bundle was used, with many tubes lumped together for model simplification. The analysis included the effect of dead weight and thermal loading for several load cases.

Basis of Studies Performed

Detailed three dimensional finite element studies of the Palo Verde steam generator tube bundle were initiated in order to gain an understanding of the causes of tube defect indications found in the upper bundle regions. Besides evaluating normal operating design geometry, thermal and flow conditions, additional load uses were considered for hypothetical boundary conditions which might result from the presence of a corrosive environment. The load cases are summarized as follows:

1. **Case A: Design Geometry, Thermal Growth and Flow Loads**

   Under normal operating conditions, tube-to-tube support contact forces do occur due to differential thermal expansion. However, a 3-D analysis of this effect was not performed during the steam generator design phase. Since the tube wear indications were occurring in localized regions, a 3-D model evaluation was deemed appropriate.

   Tube-to-tube support contact forces due to differential thermal expansion were found to be quite low (less than 1.0 lbs. in general). Also, calculated flow forces throughout the bundle were found to be much smaller than dead weight and acting in the opposite direction. Thus, tube bundle interaction forces from normal operational loading were not unusual and did not indicate a relationship with the tube defect indication pattern found at Palo Verde.

2. **Case B: Dead Weight Plus Thermal Loading**

   This condition was evaluated in order to provide a comparison of thermal loads with normal dead weight.

   The results of this analysis indicated the dead weight reactions were generally larger and acted in the opposite direction of thermal loading. Regardless, the tube-to-tube support contact forces were relatively small.

G. CONTACT FORCES (cont.)

3. Case C: Elastic I-Beam/Vertical Support Lock-up (Zero Vertical Gap) with Thermal Growth Loading

During normal operating conditions (gap = 0.31 inch), the I-beams and vertical supports do not come into contact. However, if a zero gap condition were to exist due to corrosion or manufacturing non-conformance, additional tube-to-tube support contact forces would develop because of differential thermal expansion. It was decided to investigate this hypothetical condition to see if it would help explain reports of tube bowing.

Analysis of I-beam/vertical support lock-up showed that the I-beams were very flexible, and thus allowed the tube bundle to grow to almost the same position it would have without I-beam restraint. Tube/support contact forces remain quite low.

4. Case D: Tube/Batwing Lock-up

This hypothetical condition was also evaluated to see if sufficient reaction forces could develop at tube/batwing intersections which might cause some tubes to bow or defect into adjacent tubes.

For the hypothetical case of a tube and batwing completely bonding together (perhaps from corrosion), the analysis showed the batwing would try to restrain vertical growth of the tube and could induce significant reaction forces. Batwing and tube bending stresses (axial direction) could exceed yield. Also, the tube could deflect into adjacent tubes. However, this is a hypothetical condition and current inspection results do not confirm such a boundary condition.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

H. LOOSE PARTS ANALYSIS

1. Action Plan

Tube wear caused by loose parts was identified as a possible failure mode. To investigate this possibility, the following was performed:

a. During performance of video inspection from inside the ruptured tube, observe for indication of a foreign object on the outside of the tube and morphology of the rupture.

b. Review low frequency channel of eddy current signal for indication of the presence of loose parts.

2. Results

The video inspection from the inside of the ruptured tube did not reveal the presence of a foreign object on the outside of the tube which could have caused wear and subsequent rupture of the tube. In addition, video inspection of the annulus after removal of the ruptured tube did not reveal any indication of loose parts in the rupture area.

The rupture was observed to be a long, jagged edge, axially oriented fishmouth defect. This morphology was not consistent with that expected from a loose parts induced tube rupture. There have been two loose parts induced tube ruptures in the industry to date. The tube rupture at Prairie Island was caused by a long spring-like object captured by a flow blocking device. This condition resulted in a long, almost knife-edge morphology. The rupture at Ginna was caused by a neighboring, previously plugged, tube collapsing under the repeated impact of a large, heavy object, severing and then impacting and rupturing the neighboring unplugged tube. Since none of the surrounding tubes were previously plugged, this scenario is not a feasible root cause failure mechanism for PVNGS SG 22.

A review of the low frequency channel of the ECT data of the ruptured and surrounding tubes did not reveal the presence of foreign objects. Also, ECT revealed numerous other axial indications with characteristics similar to the ruptured tube. The low frequency channel did not indicate the presence of foreign objects associated with any of these indications. Based on these results, loose parts was eliminated as a potential root cause of the tube rupture.

I. EFFECT OF LEVEL OSCILLATION

1. Action Plan

A review of SG 22 operating data revealed that the steam generator had a history of feedwater flow and the downcomer water level oscillations. The downcomer water level data indicated that the level had fluctuated approximately $\pm$ 5% of Narrow Range (NR) with a period of 1-1/2 minutes. Following the discovery of steam generator tube damage and deposits, thermal hydraulic analyses were performed to understand the root cause of the observed phenomena and to investigate a possible link between feedwater flow oscillations and tube degradations.

Two potential adverse effects from flow oscillation that could contribute to initiation and propagation of axial cracks are:

(1) The formation of deposits is predicted by the deposit parameter to occur in a defined thermal-hydraulic zone. Level oscillations could cause thermal-hydraulic changes and result in a moving "zone" that could affect a much larger area than in a non-oscillating generator.

(2) Enhancing FIV mechanisms (either unsteady momentum or fluid-elastic instability) due to flow regime changes.

2. Results

The analyses were performed using the ATHOS II code. The operating conditions for PVNGS at 100% power used in the analysis is provided in Table V.I.1. The ATHOS output includes a summary of geometric data (see Table V.I.3), physical properties of the primary and secondary fluids and tube metal, friction correlation, and numerical parameters used in the computational procedure. The ATHOS output also includes a detailed printout of thermal-hydraulic parameters, line printer plots, and output summary of results. Table V.I.2 provides performance characteristics for the steam generator. These include hot and cold side downcomer mass flow rates, total flow and steam mass flow rates at the separator deck, circulation radio, fluid inventory and primary inlet and outlet temperatures. (Note: all values are in SI units.) Also, all the flow rates are for one-half steam generator. Due to geometric and thermal-hydraulic symmetry only 180° (90° cold and hot sides) of the steam generator were modeled by the ATHOS code.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

I. EFFECT OF LEVEL OSCILLATION (cont.)

2. Results (cont.)

The result of the analysis was determination of "Stability Ratio" for the specific cases described above. The approach to vibrational induced instability is indicated when the "Stability Ratio" is greater than one. The details of the analysis are documented in CE Report CR-9417-CSE93-1111 Revision 0. The stability ratio calculated for each of these cases (normal, high, low level) was less than unity. In other words, all cases analyzed were shown to not be experiencing excessive flow instability. It was also demonstrated that there is a negligible impact to fluid velocity, density, or stability ratio values between the normal, low and high SG level cases. Thus, the SG level oscillations described in Section V.M were determined to have essentially no impact to the upper region of the tube bundle in terms of vibration or in terms of promotion of abnormal deposition.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

J. WEAR ANALYSIS/REVIEW

A study of the 1993 Unit Two steam generator eddy current examination was conducted to evaluate the presence of tube wear in SG 21, and SG 22. Bobbin coil indications that resulted from the ECT were categorized with an MRPC probe. Those categorized as wear that were greater than 20% through-wall were included in the study. The wear indications were compared in juxtaposition with the 1991 eddy current results. The 1991 eddy current data was reanalyzed for indications which had changed by greater than 10%. Indications which had not yet been reanalyzed were excluded from this study.

Based on the results of the study, the average wear rate SG 21 and SG 22 was determined to be 11% and 10%, respectively. (Noted: the wear rates determined by this study were skewed high by the exclusion of data from wear indictions of below 20%.) These wear rates, however, should to be misconstrued as indicative of the overall rate of degradation in the steam generators. This information should be used to determine SG wear behavior, compare generators, and as a baseline for future wear studies.

The average wear rate of the 09H support was determined to be 22% of SG 21 and 18% of SG 22. That location had the largest increase in wear indications in both steam generators. The 09H support includes a scallop bar located at rows 116, 117 and 118. Tables V.J.1 through V.J.4 present a breakdown of the wear at the scallop bars. The 09H scallop bar area accounts for over 50% of total wear and new wear indications in both steam generators. (Note: for the purpose of this study new wear is defined as wear that was determined to be greater than 20% through-wall in 1993 but was not detectable with eddy current in 1991.)

Figure V.J.1 provides the location of wear indications in each steam generator. As depicted in the figures, the majority of wear in both steam generators has occurred in the 08H, 09H, BW1, and VS3 supports. Figure V.J.2 also provides the location where the majority of new wear occurred in the Unit 2 steam generators. Again, the figures depicted the majority of new wear in both steam generators as having occurred in the 08H, 09H, and BW1 supports. It should be noted that the 09H support exhibited a large amount of new wear in each steam generator. Based on the results of the study, the scallop bar at the 09H support, accounts for the majority of both the total wear and new wear. In each steam generator the BWI support did not have as much new wear as the 09H support even though it contained a higher percentage of the total wear. Although it contains a large proportion of the total wear in each steam generator, it had little of the new wear indications.

J. WEAR ANALYSIS/REVIEW (cont.)

Based on the study results, the two steam generators exhibit consistent wear patterns. The wear rates, 09H scallop bar behavior, and the location of the majority of both wear and new wear are consistent in each steam generator. The consistent wear pattern indicates that the wear is not caused by support damage or a manufacturing defect.

While it was expected that BW1 would contain the highest amount of new wear due to it having the highest percentage of total wear, the study results did not support that expectation. Rather, the results demonstrated that 09H support had the highest wear rates and percentage of new wear which, in turn, provides an indication that at least one dynamic phenomenon responsible for this change is occurring in the generators. Further study will be conducted to determine phenomenon and correct it.

K. ANALYSIS OF POTENTIAL FOR FLOW INDUCED VIBRATION

1. Action Plan

The possibility that flow induced vibration contributed to the SG tube rupture was considered during initial review of possible failure modes. It was recognized that flow induced vibration has played a significant role in SG tube degradation at other plants and in industrial heat exchangers in general.

The original CE design appeared to adequately address the issue of flow induced vibration. However, there was some physical evidence that suggested vibration may have played a role in some of the tube degradation. For example, there were some indications of cracking in areas not associated with deposits. Wear in SG 22 appeared to be significantly higher than SG 21 and the other Unit's steam generators. Tube/support interfaces were observed to have wear marks indicating tube motion relative to the support was occurring. This suggested that a distinct factor was (i.e., the same design, chemistry control, and operational history, etc.) affecting SG 22. It was also noted that the location of tube cracking appeared to correlate to a region of the generator predicted to have relatively high velocity, two phase flow. The SG ERCFA team elected to have an analytical evaluation performed to assess the potential for flow induced vibration of the SG tubes in this design.

Three flow induced vibration mechanisms can be postulated. The first is turbulence excitation. Turbulence induced vibration always exists in a flow condition, but it is of very low amplitude and requires very long period of exposure and results in wear and high cycle fatigue. Inspection of the tube crack surfaces indicated high cycle fatigue did not cause the failures.

The second mechanism results from unsteady momentum flux in the two-phase flow regime. The unsteady momentum flux in two-phase flow has been shown to produce excitation force causing both cross and parallel flow-induced vibrations. According to the experimental study, for a given natural frequency there is a flow regime within which the unsteady momentum flux is very unstable resulting in a large oscillating excitation force. This could contribute to tube damage.

The final mechanism is termed fluid-elastic instability. The exact process leading to this phenomena is not well understood but is considered a self-exciting mechanism. Fluid-elastic instability can lead to large amplitude tube motion, possible mid-span tube interaction, and correspondingly high forces generated. When a threshold for flow velocity is reached, the tube vibration amplitude rapidly increases.

K. ANALYSIS OF POTENTIAL FOR FLOW INDUCED VIBRATION (cont.)

2. Results

An analysis was performed to evaluate the two mechanisms of flow induced vibration (Reference Proprietary Report FPI-93-425). The analysis utilized results from three dimensional modeling of the SG thermal-hydraulics with the ATHOS code. The analysis made an assumption concerning the support structure. It assumed the presence of inactive horizontal supports at 08H and 09H. It was only under these support conditions that flow induced vibration was predicted. The ATHOS results were used in the analysis to identify the zones of the SG tube bundle that are susceptible to flow induced vibrations.

The study investigated two mechanisms of flow-induced vibration most likely to occur in the steam generator. They include unsteady momentum flux in a two-phase flow system and fluid-elastic instability. These two mechanisms are investigated because of their potential to lead to large amplitude vibrations that can result in tube-to-tube impacting and possibly tube rupture when the flow rate exceeds a threshold value.

Since the damaged tubes observed in the steam generators of Palo Verde Unit 2 are mostly in the hot leg side of the upper tube support structure, it is assumed for the purposes of analysis that the horizontal upper tube supports in the hot leg side (08H and 09H) are ineffective. Therefore, it is assumed in this study that the horizontal supports 08H and 09H are ineffective in the direction of motion being studied. Two planes of vibration are investigated, namely, in-plane (y-z plane) and out-of-plane (x-z plane) vibrations. For the case of in-plane vibration, the in-plane restraints in y-direction on 08H and 09H are free allowing the tube bundle to move in that direction. Similarly, for the out-of-plane case, the x-direction restraints on 08H and 09H are ineffective. Based on this assumption of the boundary conditions, the fundamental natural frequencies and the mode shapes are determined for both the in-plane and out-of-plane vibration configurations.

Based on the above investigation of the stability criteria for the two mechanisms of flow induced vibration, the steam generator tube bundles which are susceptible to flow induced vibration are identified for both the in-plane and out-of-plane vibration. Figure V.K.1 shows two zones susceptible to flow induced vibration. Zone 1, which consists of the entire rows from Row 106 up to Rows 159, would be susceptible to both mechanisms of unsteady momentum flux and fluid-elastic instability. Zone 2 would be susceptible only to the fluid-elastic instability mechanism.

K. ANALYSIS OF POTENTIAL FOR FLOW INDUCED VIBRATION (cont.)

2. Results (cont.)

Figure V.K.2 shows three areas potentially susceptible to FIV out-of plane vibration. Due to a higher stiffness in the out-of-plane motion provided by the VS1 support, the rows between Zones 2 and 3 as illustrated are stable based on the prevailing cross flow velocity.

Based on the results of the vibration analyses, it is concluded that FIV could potentially be a contributor to the observed axial cracking if the 08H support was ineffective.

L. SG TUBE METALLURGICAL EXAMINATION

The scope of the metallurgical examinations intended for steam generator tube failure analysis were developed by APS Nuclear Engineering and the Inservice Inspection group and utilized the guidance provided in EPRI report NP-6743-L, Appendix C. The purpose of the examinations were intended to determine (a) tube degradation mechanisms, (b) correlations of laboratory eddy current data with field data, and (c) tube integrity testing via laboratory burst testing of defective, pulled tubing. The tube examinations were conducted at two different lab facilities, ABB-CE in Windsor, CT and B&W in Lynchburg, VA. Once the Palo Verde tube sections were received by the laboratories, the investigation process required ongoing daily planning sessions between APS metallurgists and vendor project managers and, when required, consultation with the APS Root Cause Failure Team to determine if more specific tube information was required to support the total scope of investigations.

A detailed description and purpose of each tube examination method is described as follows. Specific tube section examination results are described in the following section:

1. **Receipt Inspections:** Radioactive tube sections were received by the laboratories and documented by the Health Physics technician. Tube sections were measured for length and checked for orientation and section markings.

2. **Visual Inspections:** Tube sections were visually examined with a low power stereomicroscope to identify and characterize any tube degradation on the tube. Tube deposit visual characteristics were also determined, and any apparent damage from the tube pulling process was noted. The tube sections were photographed in the as-received condition. Areas of interest were also photographed for review and record purposes. Those areas could be selected for further investigation in addition to planned areas of interest.

3. **Eddy Current Testing (ECT):** Tube sections were selected for ECT testing using both the bobbin coil and the MRPC to precisely verify and locate tube defects for investigation. Qualified ECT personnel performed the inspections and analyzed the data. The ECT data was then used to both identify defect areas and to correlate to field ECT findings.

4. **Radiography:** This was performed on tube sections with defect areas of interest. The primary purpose was to verify the defect location and dimensional characteristics. Radiography was not sensitive to corrosion forms of degradation such as IGA or IGSCC.

L. SG TUBE METALLURGICAL EXAMINATION (cont.)

5. **Dimensional Measurements:** These measurements were performed to determine diametrical and tube wall thickness variations and to characterize any tube bend or bow. This information was needed to verify tube wall thickness specifications and to locate any bowing which could have contributed to degradation processes.

6. **Deposit Removal and Analysis:** Selected areas of tube deposit formations were identified and removed from the tube by mechanical scraping for future chemical analysis. Deposit locations and physical characteristics were noted. Deposits were then submitted for chemical analysis to identify the chemical composition and any chemical contaminants which could have contributed to a postulated corrosion degradation mechanism. The extent of deposit chemical analysis included the following:

   - X-Ray Fluorescence/Diffraction - performed to determine elemental composition and crystalline phases of deposit chemistry.

   - Mossbauer Spectroscopy - performed to determine the oxidation state of the iron in the deposits. This was necessary to positively identify the presence of magnetite, which was expected to be the prime deposit compound.

   - Leachant Analysis - included Ion Chromatography, Inductively Coupled Plasma and Flame Emission Spectroscopy to identify inorganic anions (i.e., CI, SO_4^{2-}), metallic cations (Mg, Cu, Cr, K, Ca, Pb, Al, Sn, etc.), total sulfate and organic acids. This information was important in order to determine the crevice chemistry on the tube surface and understand the potential chemical corrodents.

7. **Burst Testing:** This was performed on selected tube sections which had been identified as having tube defects, such as axial crack indications. Wear scar areas might not have been burst tested but were subjected to characterization using the test methods described below. Burst testing was intended to pressurize the tube and measure the pressure required to burst open the defect area. Once the burst was completed, the open crack surface was examined in detail (fractography) to determine the type of cracking (i.e., intergranular cracking, fatigue cracking) and depth of attack. The surface condition of the tube burst surface was also closely examined to determine if there were any surface defects present and associated with the defect. The burst pressure was correlated with the defect depth profile and analyzed for conformance with industry standards for acceptance. This data was used in tube integrity analyses for justification for alternate tube plugging studies. The burst surface was closely examined via the following methods:

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

L. SG TUBE METALLURGICAL EXAMINATION (cont.)

7. Burst Testing (cont.)

- Low Power Stereomicroscope - the surface was examined and subsequently photographed to observe the general axial extent depth of cracking or wear. Notes were taken regarding the orientation of cracking, surface condition, and extent of secondary cracking observed that was opened as a result of the burst pressure.

- Sectioning Diagram - a sectioning diagram was developed for deciding which sections were to be studied under the scanning electron microscope (SEM) and by AES and XPS.

- SEM - provided high magnification examination of the crack or wear surface. This allowed the mode of cracking to be determined, i.e., IGSCC or fatigue cracking. If the cracking was intergranular, then it was clearly visible under the SEM as the surface had a "rock candy"-like appearance. The examination was crucial for that aspect alone. The crack depth profile was also determined using the SEM. This information was important both for eddy current data analysis and corrosion attack characterization. The SEM also had the capability of performing qualitative chemical analysis of the defect surface and any associated deposits through the use of the Energy Dispersive Spectroscopy (EDS) equipment. EDS was based on X-ray fluorescence that resulted from bombarding the sample with an electron beam.

- AES - provided elemental analysis of thin corrosion films. This microanalytical technique was vital for identifying the chemical contaminants at the crack surface, as well as the degree of nominal material depletion such as chromium or nickel. This information was needed to assess the nature of the crevice environment such as whether the crevice was acidic or alkaline.

- XPS - provided elemental/compound analysis of thin corrosion films. It could add additional vital information regarding the chemical attack at the crack surface by identifying how elements were chemically combined. This information was useful in identifying corrosion products which were also indicative of the local crevice environment.

- Metallography - performed on defect areas by sectioning material cross sections, polishing, etching to show contrast with grain boundaries, and viewing under light optical microscope to verify the mode of cracking. The extent of crack branching, depth of IGA, surface condition and grain size/characterization were also determined.

L. SG TUBE METALLURGICAL EXAMINATION (cont.)

8. **Tube Material Characterization:** This work was specified to be performed to determine the material's property conformance to specifications. Material that was not in conformance with tube material specifications might have been more susceptible to failure by either corrosive or mechanical means.

   - Dual Etch - performed to assess material grain size and carbide distribution. Those properties had been shown, both through corrosion literature and field data, to have influenced the corrosion resistant properties under specific environments.

   - Modified Huey Testing - performed to determine bulk material sensitization levels in tube sections (grain boundary carbide levels). The degree of material sensitization had been shown in literature to affect the material corrosion susceptibility in various environments.

   - Bulk Chemical Analysis - performed to verify nominal chemical composition of the tube material. Discrepancies noted would have also affected the material corrosion resistance and mechanical properties.

   - Tensile Testing - performed to verify mechanical properties.

9. **Additional Testing:** While most work was focused on examining tube defect areas, additional work may be performed as the investigation proceeds and further areas of interest are identified. This may include descaling of tube sections for surface characterization, liquid penetrant testing for eddy current verification, and sectioning of selected defect areas (not burst areas) for depth profiling.

In summary, steam generator tube failure analysis can be an effective method for determining tube degradation modes and providing data for corrective action evaluation. The investigation process undertaken by PVNGS, ABB/CE and BWNS was vigorous and resource intensive. Results will be carefully evaluated against plant data, past field experience and laboratory studies involving Inconel 600 tube corrosion.

The tube examinations were conducted at two different laboratory facilities, CE in Windsor, CT and at B&W in Lynchburg, VA. (Detailed Metallurgical Analysis Reports from ABB/CE and BWNS are available.) (See Section X for references.) The division of responsibility for the pulled tubes intended for analysis included the following:

L. SG TUBE METALLURGICAL EXAMINATION (cont.)

Tubes examined at Combustion Engineering,

R117C144 - lower section of ruptured tube

R105C156 - freespan axial defect detected by Bobbin/MRPC ECT

R103C156 - freespan axial defect detected by MRPC but not Bobbin

R127C140 - 07H and 08H Eggcrate support axial defects

Tubes examined at Babcock and Wilcox,

R117C40 - freespan axial defect detected by-MRPC but not Bobbin

R116C41 - tube with no detectable defects for ECT validation

R22C13 - tube with 01H tube support plate axial defect

R29C24 - tube with 01H tube support plate axial defect

A diagram of the tube and the location of the tube cuts is provided in Figure V.C.2 through V.C.9.

Nondestructive and Destructive Testing

Nondestructive tests were performed on the tubing to characterize tube condition received at the laboratory, identify defect areas and other areas of interest, characterize deposit appearance and chemical composition. The scope of nondestructive tests included the following:

Receipt inspections

Visual inspection

Eddy Current Testing (both Bobbin and MRPC)

Double-wall radiography

Dimensional measurements

Deposit analysis.

Following the nondestructive work, destructive testing was performed on the tube defect areas to measure the remaining structural integrity of the defect areas for future analysis, characterize burst fracture faces and wear locations, determine the mode of cracking and analyze the crack oxide film chemistry to determine the local crevice chemistry environment.

L. SG TUBE METALLURGICAL EXAMINATION (cont.)

Nondestructive and Destructive Testing (cont.)

Destructive testing included the following:

- Burst testing
- Low Optical Microscopy of tube cross sections
- Scanning electron microscopy
- Auger electron spectroscopy
- X-ray photoelectron spectroscopy.

In addition to the above, tube material characterization was performed to determine the material property conformance to specifications. Material that is not in conformance with tube material specifications may be more susceptible to failure by either corrosive or mechanical means. A detailed description of metallurgical examination techniques is provided in the appendices.

While most of the effort was focused on examining tube defect areas, additional work was performed to characterize further areas of interest. This included descaling of tube sections for surface characterization, liquid penetrant testing for eddy current verification, and sectioning of selected defect areas (not burst areas) for depth profiling. A matrix of the examination results for the tubes is provided in Figure V.L.1 through V.L.8.

- **Nondestructive Testing Results**

Visual inspection of tube section under low power stereo microscope showed visual evidence of ridge deposit formation at freespan locations. Eggcrate wear locations were also verified and documented (see Figures V.L.d and V.L.e). Limited tube surface damage due to the tube pull operation was noted. Tube sections in the as-received condition were documented via photographs for future reference. Eddy current testing successfully located known defect in the tubing. Radiography proved to be of minimal use for the course of this investigation and may not be specified for future tube examinations.

L. SG TUBE METALLURGICAL EXAMINATION (cont.)

Nondestructive and Destructive Testing (cont.)

- **Burst Test Results**

  Burst testing of axial crack defects was performed both at the CE and B&W facilities. The test results are discussed in a later section of this report as part of the Regulatory Guide 1.121 discussion. In general, tube R105C156 exhibited a burst opening length of 1.38 inches and a burst pressure of 3200 psig (Figure V.L.f). This tube showed a crack profile of nearly 98% through-wall cracking and was considered to be the most degraded tube examined with the exception of the actual burst tube R117C144. Tube R103C156, also a tube with a freespan axial defect, which burst at 6968 psig with a short burst length of 0.325 inches. Remaining tube burst data are covered in Section X of this report. Figures V.L.g and V.L.h show laboratory burst surfaces for tubes R127C140 and R103C156, respectively.

- **Fractography Results**

  Examination of pulled tubes with axial crack indications in the eggcrate supports and freespan areas showed a combination OD initiated IGA and IGSCC with cracking tending towards IGSCC as the degradation matured (Figures V.L.i and V.L.j). In at least one freespan tube sample, the depth of IGA appeared to be deep indicating a significant IGA component to the attack. Examination of 01H tubesheet axial defects also showed IGA/IGSCC as the mode of cracking. No transgranular cracking was observed on any tube fracture surface.

- **Low Optical Microscopy Results**

  Figures V.L.k andV.L.l are typical tube material cross-sections showing IGA and IGSCC. In some cases the IGA attack was over ten (10) grains deep, and often IGA was observed to be stemming from an IGSCC crack location. No transgranular cracking was observed during cross-sectional examinations.

L. SG TUBE METALLURGICAL EXAMINATION (cont.)

Nondestructive and Destructive Testing (cont.)

- **Deposit Investigation Results**

Long axial freespan cracks were found under freespan ridge deposits formed as a result of reduced tube clearance and from the propensity of deposits to collect at crevices at the upper part of the tube bundle. Freespan ridge deposits were determined to be as thick as four mils on the tube OD surfaces. Normal scale deposits were found to be on the order of two (2) mils thick and were not associated with any significant attack. Deposit chemical analysis showed a trend for increased concentration of normal deposit constituents and contaminants as the tube bundle height increased. Deposit analysis showed the presence of the following chemical elements/compounds: Fe_3O_4, Cu, NiO, SiO_2, CaO, MgO, ZnO, Al_2O_3, PbO, sulfur species and other minor compounds. Based on review of deposit data, it is concluded that concentration of these deposits and contaminants could facilitate IGA and IGSCC of Palo Verde's steam generator Alloy 600 tubing.

- **Oxide Film Analysis Results**

Microanalytical analysis of tube surface and crack surface films using AES and XPS concluded that the crack environment was alkaline (mild caustic) with the presence of sulfates. This is based on the evidence that showed chromium depletion at the crack tips which would only occur in an alkaline environment. The presence of sulfates and reduced sulfur on the crack surfaces was noted and was concluded to contribute to the degree of IGA and IGSCC in the alkaline to caustic environment. The evidence of some areas showing nickel depletion supports this conclusion as reduced sulfur would precipitate nickel into solution. The crack surface analysis did not indicate a strong caustic or acidic influence to the attack.

Acid sulfate attack was concluded to not be the mode of attack since there was no significant evidence of pitting and no wastage was observed. Material sensitization testing showed no indications of sensitization, thus it was concluded that the tube material was not susceptible to low temperature corrosive attack by reduced sulfur species. Crack surfaces from the 01H axial defects showed a more pronounced chromium depletion indicating an alkaline-to-caustic environment.

Lead was detected in relatively small amounts in the crack surface films and was not considered to have been a major factor in the tube cracking. Metallic copper in high concentrations was detected in both the deposits and crack surfaces associated with the upper tube bundle. The oxidizing influence of copper was not detected but it is believed to have had an influence on the rate of IGA attack.

L. SG TUBE METALLURGICAL EXAMINATION (cont.)

Nondestructive and Destructive Testing (cont.)

- **Surface Examination Results**

Tube surface examination revealed, either visually and under SEM, cracks on free span sections of tubes R103C156, R105C156, R117C40 and eggcrate defects on R127C140. Figures V.L.m, n, and o show scratches associated with IGA in tube R103C156. The surface condition of tube R127C140 -07H burst section is shown in Figures V.L.p and q. Scratched areas may result in tube surface cold working, with resultant surface tensile residual stresses. Cold worked areas are considered to be preferential sites for IGA, if thick deposits are present to provide a concentrating chemical environment, and subsequently, lead to more rapid crack initiation. Intergranular attack has been shown in laboratory tests to occur at cold worked sites which contained either tensile or compressive residual stresses. The source of the observed cold worked scratched areas has not been determined.

Examination of the lowest portion of the crack in ruptured tube R117C144 (Figure V.L.r) did not confirm the presence of cold work via scratched areas. However, the similarities to tubes R105C156 and R103C156 indicate the likelihood that the burst tube contained similar scratched areas and consequential cold working. Intergranular attack and IGSCC were found in non-cold worked areas on tubes R117C40 and R105C156, however, the depth of attack was not as severe as areas associated with cold working and ridge deposits. Other scratches and grooves believed to be associated with the tube installation process were found under normal tube scale and the resultant IGA attack was minor, approximately six mils deep in the worst areas.

- **Microstructure Examination Results**

Microstructural characterization tube R117C144 showed a microstructure absent in *intra*granular carbide precipitation, with slight *inter*granular carbide precipitation. This microstructure is not as expected for a typical high temperature mill annealed Alloy 600 material, which would normally have a semi-continuous grain boundary carbide precipitation, thus providing more IGSCC resistance in caustic environments. The cause of this microstructure in tube R117C144 was probably a combination of the heat treatment/cooling process and low carbon content.

The significance of the poor microstructure is that the material's resistance to a caustic environment is reduced. The presence of grain boundary carbides provide a mechanical strengthening effect which resists local plastic deformation and grain boundary sliding. The absence of grain boundary carbides, as observed in tube R117C144, thus reduces the materials resistance to cracking in a caustic environment.

L. SG TUBE METALLURGICAL EXAMINATION (cont.)

Nondestructive and Destructive Testing (cont.)

- **Microstructure Examination Results (cont.)**

Microstructural characterization of tubes R103C156 and R103C156 showed an improved microstructure compared to R117C144, but were less than what is recognized as optimum today. The presence of intragranular and intergranular carbides and prior carbide grain boundaries indicates that the annealing heat treatment was not a full solution anneal which would have dissolved all carbides, promoted grain growth and provided an inventory of carbon for grain boundary precipitation during cooldown. This results in a lower material resistance to intergranular cracking in the caustic environment. Microstructure evaluation of examined tubes (R127C140, R117C40, R116C41, R22C13 and R29C24) showed a marginal but acceptable tube microstructure.

- **Wear Examination Results**

Wear indications were also examined in the lab by visual inspection, cross-sectional metallography and SEM. The most significant wear was noted in tube R116C41, located at the upper 09H support/scallop bar location (Figure V.L.s). The wear appearance was shiny and showed evidence of being an active wear location. Depth of wear was measured to be approximately 25%. The cause of wear is believed to be due to sliding-impact wear. Other wear locations were examined on tubes R103C156 (06H) (Figure V.L.t) and R117C144 (07H) support locations. These wear scars were shallower in depth and had a thin layer of deposits on the tube surface indicating that the wear was not recent. Shallow IGA was noted to be associated with the wear at these locations. This is due to the surface cold working and crevice environment at the eggcrate supports. Burst testing of the wear and associated IGA located in tube R117C144 07H support revealed leaking at 8000 psig indicating significant structural strength remaining in these areas.

- **Eddy Current Validation Results**

Sections of tubing on R105C156 and R103C156 at the 07H eggcrate support location and the entire tube surface on tube R116C41 were found to have no detectable defects by field eddy current testing. These sections were subsequently examined in the lab to verify that there was no detectable IGA/IGSCC degradation on the tube. These sections were hydraulically swollen to open any surface defects that might be present, descaled and then liquid penetrant examined. The results showed only minor IGA with one isolated area on tube R116C41 that had IGA/IGSCC believe to be approximately 27% through-wall at the 09H support location.

L. SG TUBE METALLURGICAL EXAMINATION (cont.)

Nondestructive and Destructive Testing (cont.)

- **Eddy Current Validation Results (cont.)**

  The test results confirmed that the tube sections examined for ECT verification did not have degradation that was above field ECT thresholds.

- **Material Testing Results**

  Material chemistry and tensile testing showed that the pulled tubing met the PVNGS steam generator specification for Alloy 600 tubing material. Tensile testing of all tube samples also showed conformance to the specification.

- **Summary of Ruptured Tube Findings**

  In summary, tube R117C144 ruptured due to IGA/IGSCC attack in an alkaline-to-caustic with sulfate environment associated with freespan deposits. The detection of cold working due to scratched areas associated with long defects on tubes R105C156 and R103C156 indicate that a cold worked surface area most likely was present which led to an early crack initiation time. Microstructural evidence showed that tube R117C144 would have the least resistance to IGSCC compared to other tubes examined. However, the effect is considered to be secondary based on tube R127C140 results which showed a through-wall crack at the 07H support location that was associated with surface damage but had a lower concentration of deposits and an acceptable microstructure.

  Freespan tube degradation found in tubes R105C156 and R103C156 is concluded to be consistent with the damage mechanism found on tube R117C144. The crevice environment was concluded to be alkaline-to-caustic with sulfate formed under freespan crevice deposits. The worst cracking was long and tended to occur at locations of cold working. These tubes also had marginal microstructures but not to the degree of the ruptured tube. Of the two tubes, tube R105C156 was the most severely degraded. Freespan tube R117C40, piece 17 was found to have IGA/IGSCC associated with ridge deposit build-up. The average and through-wall penetrations were 27% and 61%, respectively. These results showed that scratches are not required for IGA/IGSCC to occur.

M. OPERATIONAL REVIEW

1. Action Plan

A review of pertinent operational issues was performed to determine their relevancy or impact on Unit 2's steam generators and the tube rupture. The review included the level oscillations that occurred in Unit 2 (both generators) and comparison to Unit's 1 and 3, comparison of the unit's cumulative thermal generation, comparison of secondary pressure performance, and possible vibration and/or loose parts in the generators. The review did not address operational chemistry issues which are discussed in detail in Section V.N.

2. Results

Operating records for all three were reviewed to discern any operating concerns/ activities that may have been unique to Unit 2.

a. Feedwater Level Oscillations

Operationally, the most significant difference between Unit 2's steam generators and those of Units 1 and 3 was the presence of a level oscillation in Unit 2. The oscillation occurred first in SG 22, although it later occurred in SG 21 as well. The apparent cause of the level oscillations was a failure of the positioner for SG 21's economizer valve (2J-SGN-FV-1112).

The following scenario describes the effect of the failure:

(1) As SG 21's level deviated from the normal value of 50%, the feedwater control system developed an error signal.

(2) The SG 21 economizer valve failed to respond, resulting in the level continuing to deviate further and increasing the magnitude of the error signal.

(3) The main feedwater pump turbines, which are also driven by the error signal, would increase or decrease speed to return SG 21 to the 50% level setpoint.

(4) Because the main feedwater pumps deliver feed to both steam generators, the change in speed would also vary flow to SG 22, causing the observed level oscillation. In summary, the feedwater control system "drove" SG 22 level in its operation to maintain SG 21 level. (Note: The scenario described above only applies when the main feedwater pump high-select gate in the feedwater control system receives a nominally higher signal from the #1 feedwater control system cabinet. Based on discussion with the responsible engineer, the signal from the #1 cabinet was ~0.4 volts higher than #2.)

M. OPERATIONAL REVIEW (cont.)

2. Results (cont.)

a. Feedwater Level Oscillations (cont.)

- **Unit 2 - Steam Generator #2**

The team reviewed 2J-SGN-LR-1121, the hard-copy chart recorder output, from June 23, 1992, to the SGTR event date. 2J-SGN-LR-1121 displays the two narrow range SG 22 level transmitters (LT-1121 and LT-1122) that input into the Feedwater Control System. The June and July 1992 recorder output was nominal. The trace appeared as an almost solid line approximately 1-1/2 to 2% wide. The frequency of these nominal oscillations appeared to be about 40 per hour.

During blowdown, the magnitude rose to about 2 to 2-1/2% and the frequency dropped to about 20 oscillations per hour. In addition to operator interviews, the team reviewed chart recorder output just prior to the last outage (2R3, commenced October 17, 1991) and prior to an unrelated reactor trip which occurred on November 23, 1987. The level of performance was comparable to observations of all three Palo Verde units in the past.

Based on operator interviews and chart recorder output, slight level oscillations began to emerge in early August, 1992 (e.g., 8/4/92). This included peak-to-peak oscillations of about 4%. These spikes were only detectable until August 6, 1992. On September 7, 1992, the duty Shift Technical Advisor initiated Condition Report/Disposition Request (CRDR) 2-2-0282, identifying the appearance of 5% oscillations. A similar CRDR was written on September 12th (2-2-0287) to establish a continuing trend. A third CRDR, 2-2-0286, also dated September 12th, noted the same erratic operation during high rate blowdown. The return of the oscillation was also visible on the chart recorder output. The oscillations reached about 5% peak-to-peak. The oscillations lessened in magnitude at approximately 11 pm, October 2nd and stopped completely at 3:30 pm on October 4, 1992.

At 3:00 am, October 8th, the oscillations started to reappear, and rather abruptly, returned to previous high levels at 3:00 pm that same day. Unit Maintenance replaced the actuator on the "B" heater drain tank level control valve (2J-EDN-LV-502, work order 00573300) on November 6th to correct that valve's cycling, but SG 22's level continued to oscillate. On November 12th, clean-out pins on the control valve positioner nozzles were exercised in an attempt to improve performance but had little or no effect. A reactor trip, from an unrelated cause, occurred on November 13, 1992. During that outage, both steam generator economizer valves were recalibrated.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

M. OPERATIONAL REVIEW (cont.)

2. Results (cont.)

a. Feedwater Level Oscillations (cont.)

- **Unit 2 - Steam Generator #2 (cont.)**

  After start-up from the November 13, 1992 trip, SG 22's level was stable again. At the time, occasional oscillations were observed, but at a lower frequency, typically hours apart. On December 8, 1992, however, the frequency returned to earlier levels. The condition persisted with the oscillations gradually increasing in magnitude and frequency. By the end of February, 1993, peak-to-peak oscillations of 8% were common. At the time immediately prior to the tube rupture, SG 22's level oscillations were about 3 to 5% peak-to-peak.

- **Unit 2 - Steam Generator #1**

  The team reviewed the Unit 2 steam generator level recorder (2J-SGND-LR-1111) hard-copy output from July 30, 1992, until the SGTR event date. Level recorder LR-1111 displays the two narrow range SG 21 level transmitters (LT-1111 and LT-1112) that measure steam generator level and input into the Feedwater Control System. The recorder output from July through December, 1992, was nominal. The trace appeared as an almost solid line approximately 2 to 3% wide. The frequency of these nominal oscillations appeared to be about 40 per hour. During blowdown, the magnitude rose to about 4% and the frequency dropped to about 30 oscillations per hour. In addition to operator interviews, the team reviewed chart recorder output just prior to the last outage (2R3 commenced October 17, 1991) and prior to an unrelated reactor trip which occurred on November 23, 1987. The level of performance was comparable to observations of all three Palo Verde units in the past.

- **Unit 2 - Steam Generator #1**

  Oscillations started to emerge in SG 21 on January 9, 1993. These indications were 4 to 5% peak-to-peak. They occurred sporadically but were consistent (e.g., 10-15 per hour) and larger (~7%) by January 23, 1993. At the time of the tube rupture in SG 22, the SG 21 level was oscillating at about 3 to 5% peak-to-peak.

M. OPERATIONAL REVIEW (cont.)

2. Results (cont.)

a. Feedwater Level Oscillations (cont.)

- **Unit 1 and 3 Steam Generators**

  Recorder charts and interviews in Units 1 and 3 did not indicate that the other units had experienced the level oscillations observed in Unit 2. The level recorder trace width was a nominal 1 to 2% wide for both steam generators in each unaffected unit. In addition to interviews, several historical recorder traces were reviewed and showed no evidence of level oscillations in the past.

  Modeling of the steam generator thermal hydraulics was utilized to evaluate the possible effects of the level oscillations. The action plan and results of this analysis are provided in Section V.I.

b. Cumulative Thermal Generation

Cumulative thermal generation, which is directly related to the steam drawn from the steam generators, was higher in Unit 2 than either Units 1 or 3. As of March 31, 1993, the cumulative thermal generation per unit was:

Unit 1 133,692,750 megawatt-hours
Unit 2 150,594,902 megawatt-hours
Unit 3 119,595,086 megawatt-hours

Assuming that Unit 1 operates at 100% power (3800 megawatts) with no coastdown until its scheduled refueling outage, September 4, 1993, its thermal generation will have reached approximately 148,011,150 megawatt-hours. At that time, Unit 1's thermal generation will be equivalent to Unit 2's at the time of the tube rupture.

If it is assumed that Unit 3 operates at 100% power (3800 megawatts) with no coastdown until its scheduled refueling outage, March 15, 1994, its thermal generation will reach approximately 151,423,886 megawatt-hours. Thus, Unit 3's thermal generation would approximately equal the same exposure Unit 2 had reached at the time of the tube rupture.

M. OPERATIONAL REVIEW (cont.)

2. Results (cont.)

c. Comparing Steam Generator Secondary Pressure Performance

In the past, Unit 2 operators noted that Unit 2's steam generator secondary pressures (as measured in psia) were lower than Units 1 or 3. Additionally, Unit 2's SG 22 indicated 3 to 4 psi lower than SG 21. Also, Unit 2's electrical output dropped 8 to 10 megawatts during the past operating cycle. The team concluded that the secondary pressure observations were normal and were neither precursors to the tube failure, nor related to the root cause of the tube rupture.

d. Vibration/Loose Parts

Numerous vibration/loose parts alarms were received in the Unit 2 control room during the last operating cycle. On some occasions, the alarms were classified as "high-rate" (greater than 4 per shift.) The alarms, however, cleared during abnormal rate blowdowns. The Vibration Group identified that the majority of the alarms were on the reactor coolant pumps sensors and not on the steam generators. The Vibration Group analyzed the recorded data, including the potential for signals that originated in the steam generator but were detected at the distant probes. Based on analysis of the captured detector signals, the Vibration Group determined that even if some alarms were from the steam generators, they did not originate from the level where the tube rupture occurred. In addition, the alarm rate and times did not relate to the frequency of steam generator level oscillations.

Although a loose part could have been created during a failure of the "B" main feedwater pump discharge check valve during power ascension from the 2R3 outage, in order for it to have had an impact on the ruptured tube, any broken parts would have had to travel through the tubes of all three high pressure feedwater heaters. The vibration and loose parts monitoring equipment provided no indication of loose parts coinciding with the check valve failure and the height and location of the tube rupture also cast further doubt on the loose part as a cause of failure.

N. CHEMISTRY REVIEW AND EVALUATION

Investigation and research of pertinent chemistry data and parameters was evaluated. The following information is the results of the data reviewed.

1. Feedwater Flow Rate

A review of the feedwater flow data for Unit 2 Cycle 4 was conducted to determine if there was a difference in feedwater flow rates to the steam generators.

The data indicated that the average mass flow rate to each generator was about 8,750 Klb/hr, and that the mass flow rate to SG 21 was approximately 100 Klb/hr higher than SG 22. This is a difference of 1.15%.

Ionic impurities are homogeneous in the feedwater; therefore, 1.15% more impurities would have been transported to SG 21. However, based on the fact that SG 22 had more defect indications than SG 21, the difference in the mass of feedwater flow is not considered to be a contributor to the tube rupture.

2. Blowdown Flow Rate

A review of blowdown flow rates and effectiveness was conducted to determine whether blowdown practices would account for substantial differences between the steam generators.

In the past, the steam generator blowdown flow rates for Units 1, 2 and 3 have varied (as a result of chemistry data and blowdown philosophy). Unit 2 has typically had longer periods of abnormal rates of blowdown than Units 1 and 3. The typical blowdown regime has been 2 hours of abnormal blowdown each night and two minutes high rate blowdown per hot leg and cold leg twice a week. In 1992 Unit 1 and 3 began the twice a week, two-minute high rate blowdown for hot leg and cold leg followed by a two-hour abnormal blowdown. Other changes in the blowdown flow rate varied depending upon transient chemistry conditions.

Blowdown effectiveness had been evaluated through a number of studies. In 1986 a lithium injection test and an ATHOS modeling of the SG, sponsored by EPRI, suggested that the economizer feedwater had a significant contribution to the blowdown. Additionally, a review of the plant downcomer versus hot leg data, along with the EPRI tracer injection test, supported the above findings. The ABB tube bundle chemistry model considered these observations and predicted that the blowdown water contained 80-90% feedwater.

Blowdown flow tests conducted in Unit 2 during the EPRI tracer injection study (August 1992) showed the normal SG blowdown flow rate to be nearly equivalent between SG 21 and SG 22. However, the abnormal SG blowdown flow rate was a factor of two higher for SG 22 than SG 21.

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

2. Blowdown Flow Rate (cont.)

Normal blowdown flow only removes about 10 to 20% steam generator water and 80 to 90% from feedwater. The Unit 2 blowdown program should have removed more ionic impurities from SG 22 than SG 21 (based on the 1992 tracer injection test data). Therefore, the differences observed in the blowdown flow rates does not provide evidence to support the higher defect indications in SG 22.

3. Hideout Return Studies

A review of data, obtained during shutdowns in the three Palo Verde units, was conducted to determine whether there were any differences in the hideout return characteristics of the six steam generators.

Hideout return data is considered the most accurate indicator of the chemistry present within steam generator crevices during operation, as such, can provide insight into potential damage mechanisms.

A total of 53 shutdown data sets covering January, 1987, through March, 1993, were reviewed. Data for shutdowns that occurred prior to January, 1991, were reviewed for peak concentrations observed during the shutdown. More recent shutdown data was reviewed with cumulative grams returned quantified. In addition, samples were taken from the flow distribution plate (hot leg).

A summary of peak concentration data from 1987-1993 is presented in Table V.N.1. The data included are:

- The average chloride, sulfate and sodium peak concentrations observed during the shutdown,
- The calculated ratios of sodium divided by chloride plus sulfate (cation/anion balance),
- The calculated molar ratios of sodium divided by chloride, and
- In each unit the ratio between SG 21 and SG 22 for each impurity (SG 21 divided SG 22)

The following trends were noted:

- The average peak sodium hideout return concentration was significantly higher in SG 22 (Unit 2, SG 2) than in SG 21 (Unit 2, SG.1)(270 ppb vs. 172 ppb). The other units do not show this trend.
- The average peak sodium hideout return concentration from SG 22 is higher than any other steam generator.

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

3. Hideout Return Studies (cont.)

- The molar ratio calculated from the average hideout return peak concentrations of sodium and chloride are higher in SG 22 than SG 21 (19.2 vs. 2.9).

- The 1991-1993 hideout return data indicates that Unit 2 has had the highest return of sodium and sulfate, and the lowest return of chloride.

The following is a compilation of information derived from these detailed hideout return programs.

Hideout return data (1991-1993) obtained in accordance with 74DP-9ZZ06, Hideout Return, is much more extensive and provides for quantification of grams returned for 12 species and an estimation of crevice pH (MULTEQ) and is also summarized in Figure VN.1. Included in the table is:

- The average grams returned during the shutdown from each generator, and

- The MULTEQ predicted crevice pH during operation as determined from sodium, chloride, sulfate, calcium, magnesium, silica, potassium, etc.

- MULTEQ calculated at temperature crevice pH values, are essentially identical in all three units. All MULTEQ analyses indicate an excess of caustic is present at operating temperatures. The MULTEQ data predicts pH values in the range of 9.6-10.7 in each unit when utilizing the prompt hideout return data and allowing MULTEQ to remove precipitates as they form. If cumulative data is utilized and MULTEQ allows precipitates to remain within the crevice solution, the pH range is 8.6-10.7. The lower pH prediction is due to the highest concentration of sulfate (acidic species) is returned as the unit cools down and the cumulative data is used in as MULTEQ.

- The concentrations of lead returned from the Unit 2 steam generators during the 1991 shutdown was considerably higher than that observed from the other units (1992-1993 data).

- The available hideout return chemistry data suggests that all three units operate with caustic crevices. EPRI data suggests a greater than tenfold increase in stress corrosion cracking growth rates as the high temperature pH exceeds 9.0. EPRI data suggests a greater than tenfold increase in intergranular attack (IGA) rates as the high temperature pH exceeds 10.0.

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

3. Hideout Return Studies (cont.)

- The quantity of lead removed during the October 1991 shutdown in Unit 2 was high in comparison to that observed in Units 1 and 3. The quantity returned did not differ between SG 21 (18 grams) and SG 22 (20 grams). The presence of lead is believed by various EPRI references, to promote intergranular corrosion, with the most severe impact observed where lead is in combination with strongly caustic environments.

The peak concentrations of sulfate, as well as the cumulative grams returned of sulfate, are high in all three units. Although the previous shutdown data suggests the sulfate is not associated with the prompt hideout return data (i.e., the sulfate is not concentrating within crevice areas), the quantities of sulfate which have accumulated within the steam generators during operation are high. High concentrations are typically observed by most utilities due to the absorption of sulfate species.

4. Sulfate Source

An assessment of sulfate in the secondary cycle was conducted due to the implications of sulfate causing intergranular stress corrosion cracking.

Areas reviewed included quantification of sulfate sources to the secondary, hideout return data and resin intrusion events. In addition, an action plan was implemented to determine the potential effects of resin fines observed on the steam generator can deck during 2R4.

- **Source Term Study**

  Due to hideout return chemistry continuing to indicate caustic crevice environments, a two-week source term study was concluded in 1992 to characterize the impurity sources to the steam generators. The condensate polisher influent quantities of sulfate were found to be approximately 28 lbs., indicating that the polishers reduced the sulfate by approximately 15%.

  The results of the source term study estimated that 22 lbs. of sulfate per year would be transported to the steam generators from condensate polisher operations assuming full flow polisher operations. If the polishers were bypassed, and assuming a condenser tube leak of 0.001 gallons per minute, the study estimates that 23 lbs. of sulfate per year could be transported to the generators due to a condenser tube leak. Normal chemical injection and the Condensate Storage Tank (CST) makeup source were negligible sources for sulfate. No specific monitoring of sulfates from resin fines/beads was conducted.

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

4. Sulfate Source (cont.)

- **Source Term Study (cont.)**

Comparable amounts of sodium (27 lbs.) and chloride (25 lbs.) were also found in the demineralizer effluent source. In addition, the cooling water ingress quantities of sodium and chloride were similar to those of sulfate. In comparing those findings with the current typical steam generator blowdown chemistry, the hideout rate for chloride is the lowest and sulfate is the highest. These findings are consistent with those above, since the daily chemistry typically shows sulfate is the lowest impurity present in the blowdown and chloride is the highest.

- **Sulfate Hideout Return**

The average concentrations of sulfate observed (1987-1993) during hideout return were:

Unit 1	251 ppb
Unit 2	218 ppb
Unit 3	234 ppb

The concentration amounts confirm that a significant amount of sulfate has been transported to the steam generators and hideout is occurring. There are only minor differences (<10%) in sulfate concentrations among the three units and between the two steam generators within each unit. Overall, the highest concentrations of sulfate have not been seen in the prompt hideout return (defined as the first 4 hours following shutdown to 0% power). This would indicate that the majority of the sulfate was not concentrated within steam generator crevices but was absorbed on all steam generator internal surfaces as a precipitate such as calcium sulfate.

Sulfate concentrations typically increase when the unit cools down to less than 400°F. Such action is consistent with the inverse solubility relationship between calcium sulfate and temperature. During the most recent shutdowns at both Units 1 and 3, the prompt concentrations of sulfate were higher than had been recorded in prior shutdowns. Hideout return samples were not collected in the March 1993 shutdown of Unit 2. As a result, the increasing concentrations of sulfate may have an impact in the crevice environment. The increased prompt sulfate return has occurred as the molar ratios have been reduced within the past six months. This may be consistent with the practice of bypassing the condensate demineralizers anion regenerations which may promote some anion leakage but more information is needed to confirm that relationship.

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

4. Sulfate Source (cont.)

- **Sulfate Hideout Return (cont.)**

Sulfates, however, have a much lower impact on depressing the crevice pH than the chloride ion exhibits. Findings of elevated concentrations of sulfate, therefore, may not correlate to the existence of acidic conditions within the crevices.

- **Resin Intrusions**

In addition to the sulfate intrusion that can result from the regeneration process, sulfate can be introduced into the steam generators from the actual resins. It is difficult to prevent the escape of resin particles from condensate polishing units, and significant leakage from deep-bed polishers has been reported in industry sources such as those referenced in EPRI NP-5802, May, 1988, "Method for Detecting Resin Leakage in LWR Coolant" and EPRI NP-3046, June, 1983, "Evaluation of Condensate Polishers" particularly during transient periods. When that type of leakage occurs, the particles enter the high temperature cycle where thermal degradation of the cation exchange resin occurs and results in the formation of corrosive sulfur-bearing compounds. Heat degrades ion-exchange resins by splitting off organic molecular fragments of styrene divinylbenzene/ copolymer as well as the sulfate and methyl amines that represent the active ion exchanging sites.

In an operating unit, if sufficient resin was released to the feedwater, such as by a failure in a polisher's resins trap, then an increase in sulfate and/or TOC would be observed in the steam generator blowdown. PVNGS has not been equipped with the sensitive equipment necessary to monitor low levels of resin intrusion (e.g., high pressure liquid chromatography with fluorescence detector). Known failures of the condensate demineralizer resin retention screen have occurred on two occasions in U2. There have been no know failures in Unit 1 or 3. In the past, U2 has observed resin fines on the corrosion product sampler filters which supports the release of resin from the condensate demineralizers. U2 also observed resin fines on the can deck of the steam generators during the 2R4. A review of the steam generator blowdown data following these two resin intrusions identified a significant increase in sulfate concentrations following the 1992 event. Sulfate levels increased to 78 ppb in SG 21 on January 24, 1992. SG 22 sulfate levels increased to 102 ppb on this date.

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

4. Sulfate Source (cont.)

- **Resin Intrusions (cont.)**

Following this event, U2 remained at power until March 23, 1992. During the shutdown on March 23, the sulfate hideout return values peaked at 336 ppb, a value which is greater than the average peak sulfate observed for SG 22 (270 ppb). The unit remained in hot standby during this outage; therefore, a complete removal of the sulfate was not achieved due to the retrograde solubility effect of the sulfate compounds. The first full shutdown following this resin intrusion event occurred following the SGTR event March 14, 1993. Due to the complexity of the shutdown only a small number of samples were obtained; however, a peak sulfate value of 928 ppb was noted in SG 22. SG 21 sulfate peaked at 666 ppb. These levels of sulfate are approximately 3 times those observed during previous U2 shutdowns. (Note that the 928 and 666 ppb values were obtained from the inline Ion Chromatograph, and should only be considered as an estimate.) No increase in sulfate was identified during U2R3.

- Cation Resin

The breakdown products of cation resin are potentially damaging if concentrated within the steam generators. Cation resin will begin decomposing at approximately 180°F and result in the formation of sulfur trioxide which in turn reacts with water to form sulfuric acid. Graver Chemical Company has stated that at 300-400°F all sulfuric acid will be released "in a matter of weeks or hours." At higher temperatures, the divinylbenzene polymer 3-dimensional backbone will unzip resulting in DVB monomers.

This will result in the formation of non-reactive organics and TOC will be observed. Organic acids such as formic acid and acetic acid may also be observed. Graver also considers that an alcohol group can result in the presence of oxygen. DOW Chemical, the manufacturer of the 550A and 650C resins used in Unit 2, does not consider the melting of the resin backbone to be a viable possibility. The resin would disappear by turning into carbon dioxide (CO_2) and volatilizing off. Among the vendors, there has been no consistent determination as to the temperature at which the final destruction of the monomer would occur.

If the functional groups have been removed by the initial stages of the decomposition process, the remaining backbone is not considered a problem. The levels of organic acids which would result would not be of significance, and the TOC values which have historically been observed in the steam generator blowdown would be less than detectable.

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

4. Sulfate Source (cont.)

- **Resin Intrusions (cont.)**

  - Anion Resin

    The Anion Resin has a backbone identical to the cation resin and as a result, should be insignificant in its final stages of decomposition. In the initial stages of anion resin decomposition, which occurs very rapidly, and at a lower temperature than with cation resin, volatile amines would be released. Dimethylamine and trimethylamine would be likely products and would have identical effects as the ammonia and hydrazine used for secondary chemistry control. Graver also considers chlorinated organics as a possible decomposition product but, as discussed previously, significant levels of TOC's have not been observed in the Palo Verde secondary systems.

    Based on the previous, the decomposition products of anion resin is not considered to be damaging to the system.

  - Inert Resin

    Inert resin was used in the past at Palo Verde. It was, however, removed from the resin charges during the May 1992 time frame to allow for increased cation resin inventory. Inert resin has an identical backbone to both the cation and anion resins. Inert resin has not received any further chemical treatment such as that received by cation and anion resins, and is therefore not considered a chemistry issue.

  - Unit 2 Steam Generator Can Deck Resin Contamination

    Resin was found on both SG 1 and SG 2 can decks in 2R4. Visual inspections of both can decks were conducted and the accessible area in SG 1 was "vacuumed" out to obtain the resin. The resin was used to assess the quantity of resin remaining on the can deck and determine if the cation resins' functional groups remained intact. The following resin contamination action plan was implemented, and out of the approximate 10 square feet area vacuumed, approximately one gram of resin was obtained. The resin was then tested to see if the functional groups remained.

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

4. Sulfate Source (cont.)

- **Resin Intrusions (cont.)**

  - Unit 2 Steam Generator Can Deck Resin Contamination (cont.)

The initial step was to determine the quantity of resin remaining within the steam generator. Depending upon the amount of resin remaining, it would be necessary to determine whether there were any cation resin functionality groups remaining. The cation resin functional groups are sulfonic bearing which may decompose to sulfuric acid when exposed to steam generator temperatures. If this had already taken place, the remaining cation resin would be inert. Any inert resin present would not cause a problem from a chemical point of view. Anion resin would not pose a problem either.

The following test was designed as a go/no go test and could be performed remotely without analytical equipment. To determine if any functional groups are remaining on the cation resin:

1. Prepare a saturated sodium chloride solution. Fill a 250 ml (approximately) clear container with the saturated salt solution.

2. Add several grams of the resin to be tested to the clear flask and agitate.

3. Observe whether any resin falls to the bottom of the flask.

If any cation resin with intact functional groups were remaining, these resin beads would drop to the bottom of the flask due to their density being higher than either inert resin, anion resin, or cation resin with no functional groups remaining. If none of the resin sinks, the resin would pose no chemical problem. If some of the resin sinks, it would mean either:

1. Functional cation groups are present, or

2. The resin may be fouled with iron, etc., which would make it more dense.

Therefore, if the above go/no go tests results in sinking resin, it would be necessary to rule out the possibility of fouled resin. This could be done by to removing the iron fouling by acid dissolution or ultrasonic cleaning, rinsing, and then repeating the salt test.

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

4. Sulfate Source (cont.)

- **Resin Intrusions (cont.)**

  - Unit 2 Steam Generator Can Deck Resin Contamination (cont.)

    Based upon the results of the can deck inspection and subsequent resin analysis, it was determined that:

    - The resin volume remaining on the SG can decks is insignificant.
    - The cation resin had lost the majority of its functional groups, and thus any sulfate contribution to the SG had already occurred.

  - Condensate Demineralizer Retention Elements

    Further investigations on the failure of the retention elements, within the condensate demins, as a potential cause of the resin intrusion is under way; refer to CRDR 2-3-0411.

5. EPRI Tracer Test

A hideout evaluation test was performed at Unit 2 from 8/18 to 8/22/92.

The test had a two fold purpose:

(1) Measure the impurity accumulation (i.e., hideout) in the crevice regions of the steam generator and

(2) Measure the abnormal and normal blowdown flow rates from each steam generator.

The calculated hideout fractions differed between the two SG's. The difference is currently being evaluated by EPRI. The vendor model was modified for a CE System 80 plant and determined the following hideout fractions, chloride 70%, sodium 80%, potassium 89%, sulfate 100% and calcium 100%. The vendor model was modified to account for condenser cooling water inleakage and to account for higher than expected mainstream carryover.

Based upon the tracer injection test, the majority of impurities introduced into the steam generators stay in the steam generators during the operating cycle.

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

6. Sampling Methodology

A review of sampling methodology was conducted to determine the differences between the hot leg and downcomer sample points. In addition, CE model data were reviewed to determine whether local concentrating effects could be predicted, and whether hotleg blowdown samples were representative of steam generator hot leg side bulk regions.

Prior to 1993, the hot leg sample point was used to monitor and control steam generator chemistry. The downcomer sample is currently used due to information gathered from various sources. These sources include a lithium tracer study conducted by APS and CE (V-CE-34773 dated June 16, 1987), an EPRI sponsored tracer injection test performed by NWT Corporation (EPRI S401-1 topical report March, 1993), a blowdown flow model developed by CE (CRDRC Report 4039/1 January, 1993) and comparisons of Site Chemistry's steam generator blowdown sample database.

The available data indicate the downcomer sample point is more representative of the local chemistry environment within the hotleg tube bundle based upon the following:

- Inline instrumentation and grab samples indicate the downcomer sample impurity concentrations are approximately a factor of 5 higher than the hotleg sample.

- The downcomer sample indicates impurity ingress earlier than the hotleg sample. The downcomer sample point also is the most sensitive to the determination of cleanup following an impurity ingress.

- The CE model predicts a concentration factor of 2.5 greater at the top of the hot leg side tube bundle as compared to the hot leg side tubesheet.

- The CE model predicts that hot leg blowdown contains 80-90% feedwater.

With the units now sampling from the downcomer sample point, the SG bulk water chemistry reflects the more concentrated faction at the top of the tube bundle.

Thus, with known deposits on the tubes, a more concentrated and aggressive environment will be present at the top of the tube bundle.

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

7. Condenser Leaks

A review of condenser tube leaks was conducted to determine whether different frequencies of occurrence among the units existed. In addition, the most severe event was reviewed to determine whether an impact to the steam generators resulted.

A "Condenser Tube Leak Assessment" was conducted by Systems Engineering. The assessment determined that lathing was installed in the condensers to stabilize the tubing.

Unit 2 has experienced approximately two times the number of condenser tube leaks over its life, than the other two units. One leak in 1990 was particularly severe, estimated at 150 gpm. During this leak, the condensate demineralizers were maintained in full flow, and no impact on the SG's was observed.

8. Operational Secondary Chemistry History

A review of steam generator operating chemistry has been completed for all three units. This review also considered changes to operational conditions and parameters

All three units have operated with essentially identical chemical control since startup (ammonia/hydrazine with full flow condensate polishing). The minor changes to secondary chemistry control which have been implemented in all three units since start-up include:

- Modifications to condensate demineralizer regeneration practices include:
  - Removal of the cation "heel." This change resulted in a reduction of sodium by approximately 50% due to enhanced separation of the cation and anion resins. (January 1989)
  - A reduction in anion resin regeneration frequencies, which resulted in an additional 50% reduction in sodium. (November 1990)
  - Assignment of designated polisher operators to operate the system. (May 1991)
  - Soaking of the regenerated anion resin charge overnight. (1992)
  - Performance of a second cation resin regeneration. (1992)
  - The replacement of inert resin with additional cation resin capacity. (1992)
  - Operating the condensate polisher in bypass. (1993)

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

8. Operational Secondary Chemistry History (cont.)

- Optimization of feedwater pH to ≥9.15 for operation with condensate polishers and deletion of upper pH specification of 9.6 for operation without polishers. This change went into effect in 1992 and resulted in an increased feedwater pH from the previous ≥8.8.

- The increase of the feedwater hydrazine concentration to >100 ppb. This change went into effect in late 1992 and resulted in an increase in hydrazine from the previous 15-20 ppb range.

- Initiation of the use of molar ratio control as a diagnostic parameter. This change became effective in 1992 and resulted in the ability to maintain the sodium to chloride ratio in steam generator blowdown to ≤1.0.

- The reduction of the feedwater iron specification to ≤10 ppb. This change became effective in 1992 and reduced the previous specification of ≤20 ppb by 50%.

- Adjustment of the molar ratio diagnostic parameter to a range of 0.5-1.2. This change became effective in 1993 when a lower limit was instituted to prevent excessively acidic conditions in the steam generators.

Each of the previous changes was made to either reduce iron transport, reduce the sodium (operating pH) in steam generator crevices, reduce the electrochemical potential, or a combination thereof.

- The operating Chemistry Performance Index (CPI) indicates that SG 1 has the highest impurity removal (highest CPI) in Units 1 and 2, while SG 2 in Unit 3 operates with the higher removal rate. This trend indicates that the two generators within each unit operate with somewhat different chemistries despite having a common source of feedwater. The change may be related to blowdown efficiency or steaming rates.

- The chemistry trends are consistent with plant operations. With the exceptions of operating beyond the anion resin break point during a condenser tube leak early in Unit 1's operating life (December 1985) and the U2 resin intrusions, there have been no other significant secondary chemistry events.

- The molar ratio trends from all three units indicate a chronic caustic chemistry control pattern. The concentrations of sodium in steam generator blowdown have consistently been well within EPRI and CEOG specifications.

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

8. Operational Secondary Chemistry History (cont.)

- High concentrations of sodium have been observed in small reactor power reductions. Concentrations of 400 ppb sodium have been observed in downpowers to 75% power. This level of sodium hideout return is not observed in Westinghouse design steam generators and may be specific to the System 80 design.

- During shutdowns, silica hideout return is consistently an order of magnitude higher than most species, including sodium. Silica can act to buffer caustic steam generator crevices and is therefore not implicated in any known steam generator defect mechanisms.

- A study of iron transport throughout the secondary system conducted in Unit 2 in 1991 determined that, under optimal conditions with condensate polishers in service, 3 lbs. of iron per day would accumulate in each steam generator. Based on those results, to-date over 5,000 lbs. of iron could have accumulated in each steam generator.

- Minimal tubesheet fouling has been observed however, indicating the potential for tube fouling. Unit 1 initiated Ethanolamine injection for pH control to reduce iron transport on April 19, 1993.

- In addition to quantifying iron transport, the soluble and particulate copper concentrations were determined in Units 1 and 3. Typical total copper concentrations were 15 parts per trillion (ppt) in the final feedwater with the condensate demineralizers bypassed and the feedwater pH maintained at 9.8 with ammonia/hydrazine chemistry control. At 15 ppt, approximately 1 lb. per year of copper would be transported to each steam generator under these conditions. Historically, copper transport quantities would presumably be lower in all three units due to the lower pH maintained previously.

- Examinations of tubing removed from SG 22 indicated the presence of copper in the deposits and within crack regions. The concentrations were low and the copper was present in an elemental form. The average concentrations of copper were approximately a factor of six times higher in the general scale deposits than in the thicker mid-span ridge deposits or the support deposits. Due to the absence of SCC under the general scale deposits, it is believed that copper has not contributed to the IGA/IGSCC. (The presence of copper has been proven in laboratory studies to significantly increase the electrochemical potential to a range which favors SCC.)

N. CHEMISTRY REVIEW AND EVALUATION (cont.)

8. Operational Secondary Chemistry History (cont.)

- Based on the available operating chemistry information, all three units may be operating with caustic crevices. This data correlates with hideout return chemistry data.

A chronic imbalance in molar ratio, high adsorption rates for sulfate, and fairly significant iron transport have been observed in Unit 2; however, these observations are similar in all three units.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

O. SECONDARY SIDE INSPECTION

1. Action Plan

A secondary side inspection of the upper tube bundle in SG 22 was performed. The purpose of the inspection was to:

a. Look for indications of the tube bundle or individual tubes being restrained from thermally expanding and

b. Compare the overall condition of the upper bundle with the condition observed during a similar inspection 2 operating cycles previous (U2R2).

The two individuals performing the inspection, one from APS and one from ABB/CE, had participated in the previous inspection of the same steam generator. This allowed a direct comparison between the two inspections to be made. The inspection consisted of the following steps:

- Observed gap between top of VS3 and 5 crescent plate and bottom of I-beam.
- Used feeler gauge to verify clearance between the crescent plates and structural angles.
- Observed number of local vertical support strip deformations for comparison with previous outage.
- Observed proximity of batwing wrapper bar to shroud. Look for evidence of contact.
- Performed general observation of condition of upper bundle. Look for distortions, changes from previous inspections.
- Observed condition of separator can splitter vanes (as was done in Unit 1).
- Viewed area on can deck near "J" tube discharge for any deposits or debris.

2. Results

The results of the secondary side inspection conducted by ABB/CE and APS are presented below:

- The gap between crescent plate and I-beam appeared to be unchanged from what had been observed previously. The feeler gage could be inserted on both sides of the two (2) crescent plates (i.e., binding of the entire tube bundle as a result of lock-up at the I-beam would be unlikely).

O. SECONDARY SIDE INSPECTION (cont.)

2. Results (cont.)

- The batwing adjacent to the ruptured tube appeared to be in accordance with the drawing requirements. The batwing twice removed (toward center of vessel) from the batwing adjacent to the ruptured tube (117/144) was deformed at the wrapper bar. The deformation appeared to be a combination of bending and torsion close to the wrapper bar. The weld connecting the deformed batwing to the wrapper bar appeared to be sound.

- With one possible exception, clearance between the wrapper bar and the inside of the shroud was clearly visible along the entire length of the wrapper bar. The space between wrapper bar and the shroud was not clearly discernible close to the 270° position of the vessel. Due to the rapid tube bundle slope which made access to the wrapper bar in the area extremely difficult, the visibility of the wrapper bar was difficult. Space existed between the wrapper bar and the shroud in the area of the ruptured tube (117/144). In order to detect if the batwings had moved, eddy current data was also reviewed. Tables V.O.1 and V.O.2 compare a selected set of batwing heights as measured by ECT in SG 22 with expected design positions. The table also compares the linearity of the batwing. Within the ability of the ECT to accurately measure height, the results did not indicate any significant shift, tilt, or distortion.

- There were no obvious differences in the physical appearance of the VS supports between this inspection (May 1993) and the previous inspection (June 1990).

- The batwings and the wrapper bar as observed on the cold leg side was nominal, i.e., no grossly bent to twisted batwings and the space between wrapper bar and the shroud was clearly discernible. The gap was slightly larger on the cold leg side than was observed on the hot leg side.

- The VS2 and the VS6 support are tied to the shroud with a sliding connection in four (4) places. The visible vertical strips of these sliding connections had a sinusoidal appearance (as opposed to straight) in the 90°/180° quadrant (hot leg) and the 0°/90° quadrant (cold leg).

The results of the secondary side inspection indicates there is no evidence of the tube bundle or individual tubes being restrained from thermally expanding. There is no discernible difference in the overall condition of the upper bundle since the inspection two cycle previous. Some individual batwing and vertical support straps were distorted upon exiting the tube bundle; however, there is no apparent relationship between these isolated occurrences and the axial crack indications. The slight sinusoidal appearance of the vertical strips at some of the VS2 and VS6 sliding connections does not appear to have a detrimental effect on the condition of the bundle and no relationship with the axial indications since most of the tubes with axial indications do not pass through the VS2 and VS6 supports.

TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

DEPOSIT FORMATION

1. Action Plan

Deposits create several opportunities for tube degradation. The deposits function as the equivalent of a crevice due to the stagnation under the deposit. Secondly, the deposit provides a "host" location for the concentration of chemicals and contaminants which differ from the bulk chemistry. Lastly, the deposits may lead to higher tube wall temperatures.

In the early phase of the root cause investigation, the Steam Generator Tube Rupture Task Force observed that the majority of the freespan and eggcrate defects as well as the bridging axial deposits were detected within a defined arc region. Based on this observation, a thermal-hydraulic analysis was performed to determine if a deposit concentrating effect could be confirmed analytically.

EPRI ATHOS code is a three-dimensional, two-phase, steady state and transient code for thermal-hydraulic analysis of recirculating U-tube steam generators. The code was developed for EPRI by CHAM of North America. The ATHOS code was further modified by Combustion Engineering to incorporate modeling of PVNGS specific geometric and process inputs, plugged, sleeved, and removed tubes. The CE version of the code also includes the capability to model sludge deposits on the tubesheet. A more detailed description of the mathematical and physical models, finite difference equations, the code structure and solution procedure is presented in EPRI sanctioned documentation.

The ATHOS code has been checked and verified by Combustion Engineering and other industry users. The validation studies included comparing the ATHOS geometry pre-processor computed values of the steam generator geometric parameters against hand calculations, checks on the mass, momentum, energy balances, and consistency and plausibility of steady-state and transient solutions for a number of different cases. For further code verification, measured data from several small-scale experiments, model steam generators, and full scale steam generators were compared with the ATHOS results. In general, there is good agreement between the ATHOS results and available experimental data.

In addition to the thermodynamic modeling to predict deposit formation, several other actions were undertaken to characterize deposit formation. For example:

- Conducting ECT, with expansions as necessary, to identify locations of deposits (PDPs)
- Conducting video inspection of deposits through pulled tube locations

P. DEPOSIT FORMATION (cont.)

1. Action Plan (cont.)

- Conducting laboratory examination of deposits (Note: detailed deposit chemistry results are discussed in the chemical results section of the report) from 8 sample locations;

  crevice and freespan, 117-40, 08H,
  crevice and freespan, 117-40, 05H,
  crevice and freespan, 117-40, 01H,
  crevice and freespan, 22-13, 01H.

  A 100g of sample was sent to Alliance laboratory for X-ray defraction (XRD) and semi-quantitative spectroscopy. The balance of samples were chemically analyzed as follows:

  - Acid digestion and deposit characterization of 05H sample, one upper bundle freespan, and one lower bundle crevice sample.

  - Leachate test, then inductively coupled plasma (ICP) on residue and solute, 01H and 08H samples.

2. Results

The following information was obtained from the study of the formation of deposits on the SG tubes.

a. Summary

Deposits from general corrosion in the secondary system and concentration of trace fecdwater impurities is a normal occurrence in steam generators. The deposits normally are characterized as sludge on horizontal surfaces, particularly the tubesheet, and a uniform boiler scale on the tubes. The nuclear industry has considerable experience with tubesheet sludge, including the crevice attack by contaminants and hideout species at the tubesheet. Similarly, the contact points created by tube intersections in supports such as the eggcrates, batwings, and vertical supports create crevices which would favor the initiation of cracks in an adverse environment, as has also been observed in the industry. The identification of 16 tubes with mid-span axial cracks in SG 21 and 87 tubes with mid-span axial cracks in SG 22 is not explained by the classic crevice experience.

P. DEPOSIT FORMATION (cont.)

2. Results (cont.)

a. Summary (cont.)

Video analysis of the secondary side is discussed in Section V.D. With respect to deposits, the video examination in the tube lanes of the pulled tubes identified three examples of close tube-to-tube proximity with a thicker axial deposit buildup bridging the area where the tubes were closer together. Similarly, two other tubes displayed a flat spot in a thicker axial deposit buildup where there had been proximity with the removed tube. Each of the four flawed full length tubes pulled from the steam generator included visual evidence of near-contact and resultant bridging deposits. The video also confirmed the presence of a deposit and bridging over five additional flaws on tubes which were not pulled. The bridging deposits had a general composition of iron oxide, similar to typical scale or fouling particulates but had higher than normal chemical contaminant concentrations. The bridging deposit acted as a "host" for the chemical contaminants which increased in concentration due to steam blanketing in the higher levels of the tube bundle as described in the deposit parameter model. Laboratory results on the pulled tubes confirmed the deposit parameter model prediction for chemical contaminant concentration increasing with height. The nominal distance between tubes is 1/4 inch, in contrast to the observations inside SG 22.

The proximity observed between adjacent tubes sets up the crevice conditions to promote cracking. Under examination in the laboratory, the most severe IGA and IGSCC was observed under the bridging deposits.

Video results were compared to the results of eddy current testing with the rotating pancake coil. The eddy current analysis identified the presence of a deposit on six out of eight of the bridging deposits viewed on the video. The classification of deposits was largely judgmental by the eddy current analysts, thus smaller signals may not classified, explaining the fact that not all visual observations were classified.

P. DEPOSIT FORMATION (cont.)

2. Results (cont.)

a. Summary (cont.)

Axial deposits were identified over 57 of the 103 mid-span axial cracks (12 of 16 in SG 21, 45 of 87 in SG 22). In addition, deposits were detected at the same height of an immediately adjacent tube in 41 of the mid-span cracks (8 SG 21, 33 in SG 22,) which was considered to be evidence that reduced spacing and deposit bridging had occurred at those cracks. Based on the comparable results of eddy current testing to the video observations, additional examples of adjacent deposits (without flaws) were located. These tube locations were also assumed to be closer together with bridging deposits. One-hundred and thirty-seven (137) sets of deposits (282 tubes) were identified in SG 21 and 71 sets (148 tubes) in SG 22. These 430 tubes are assumed to be potential future crack initiation sites or may already have cracks below the threshold of detection (≈40% through-wall for the rotating pancake coil which detected the deposit). Additional locations may exist, since experience has demonstrated that some deposits are not classified, as discussed previously.

Fifty-seven (57) of the mid-span axial cracks did not include indication of a deposit. Forty (40) of the cracks without indicated deposits were located in the area immediately above the batwing where the vertical tube begins to enter the radius, as pictured in Figure V.P.1. Although undetected over the flaws, 441 examples of deposits were noted in the same area, including 86 pairs of adjacent tubes. The lack of indication may be due to deposit detectability as the tubes begin to move away from each other.

b. Thermal-Hydraulic Deposit Models

Scale, fouling and deposits were reported in the upper region of the hot leg of the steam generator. The purpose of this section is to define a mechanism which explains the preferred location for deposit accumulation, and to identify these locations.

The detected deposits are believed to accumulate on tubes' surfaces in the upper region of the steam generator by a process associated to the two-phase flow regime in that region. This is in contrast to particulate or suspended matter which plates out at locations with low velocities such as elbows or sudden enlargements.

In a steam generator where two-phase conditions prevail in the secondary side, deposits will form at locations that experiences steam blanketing. This type of flow regime is usually avoided in the steam generator design and the heat transfer to secondary side is restricted to nucleate boiling regime (i.e., bubbly two-phase flow).

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

P. DEPOSIT FORMATION (cont.)

2. Results (cont.)

b. Thermal-Hydraulic Deposit Models (cont.)

The transition from nucleate boiling to film boiling (steam blanketing) in vertical channels has been studied extensively in the literature (see Hestroni Handbook of multiphase system). It is believed that when a function of mass flux (pV) and steam quality X exceeds a certain threshold, the transition to film boiling will occur.

In FigureV.P.2 from a B&W correlation extracted from the book, Steam/Its Generation and Use, it is seen that when pV/(1-KX) exceeds a certain value, then the flow condition will promote burnout or scale formation; here K is a constant for a given flux.

The mass flux and steam quality parameter pV/(1-KX)) is applicable under normal conditions of steam generator operations. Other factors are also known to promote the transition from nucleate boiling to steam blanketing conditions.

A survey of literature (such as Hestroni Handbook of two-phase flow) will indicate that both tube bowing and existence of transient conditions would encourage the departure from nucleate boiling.

Both of these conditions are suspected to exist in Unit 2 Steam Generator. Transients are evaluated under the flow oscillation heading and will not be addressed here. All the analysis in this section will be applicable to normal operating conditions.

The EPRI ATHOS II model, using PVNGS specific geometric and process inputs, predicted that the arc region as empirically defined by the eddy current testing was in fact a region of high deposition within the System 80 steam generator. The following information documents the development of APS's deposit model and provides the results of this analytic effort.

The PVNGS ATHOS model calculated thermal-hydraulic parameters which were used to predict a potential for chemical deposits in the upper tube bundle region of the APS Unit 2 (SG 22). An empirical deposit parameter consisting of mass flux (ρV) and concentration factor for non-volatile impurities was selected to compare with the ECT measured deposit locations in SG 22. The deposit parameter, combining thermal-hydraulic results and non-volatile chemical concentration provided a mechanistic understanding of the most probable location for the observed chemical deposits. Figure V.P.3 locates the horizontal and vertical nodalization used for the PVNGS steam generator ATHOS II Model.

P. DEPOSIT FORMATION (cont.)

2. Results (cont.)

b. Thermal-Hydraulic Deposit Models (cont.)

This chemical deposit parameter is consistent with earlier CE correlations for tube denting, sludge deposits on the tubesheet and concentration factor model for non-volatile impurities. Also, the deposit parameter is similar to critical heat flux or DNB correlations defining safe and unsafe regimes in heat exchangers.

Figure V.P.4 depicts the deposit parameter at node point IX = 3 at the middle of SG 22 hot side. The modeling results indicates maximum value between eggcrates 07H and 09H. Figures V.P.5 through V.P.14 present deposit parameter at node points IZ = 13 through 22. Based on both the analysis and available eddy current inspection data, this region of SG 22 has the highest potential for chemical deposits. Figures V.P.5 through V.P.14 also include the locations of sampling tubes with deposit indications. The tubes with deposit indications are represented by small squares. The figures encompass the full 180° of SG 22 hot side. As illustrated by these figures, the agreement between the deposit locations and the calculated chemical deposit parameter is reasonably good. Most of the measured deposits correspond to deposit parameter value of 0.7 or greater.

c. Eddy Current Examination

- Steam Generator 21

Seven hundred and fifty-nine (759) deposits (PDPs) were classified on 646 tubes in SG 21 (Figure V.P.15). Not all deposits were associated with cracks, but 8 of 16 mid-span cracks were aligned under a deposit at the same height. The details regarding the mid-span cracks that were identified are contained in Attachment V.P.1-1.

Laboratory examination identified severe IGSCC associated with bridging deposits. The PDPs identified by eddy current were reviewed for potential indications of bridging, based upon identification of deposits on adjacent tubes at overlapping heights. The SG 21 "PDP pairs with flaws" are detailed in Attachment V.P.1-2.

PDP pairs without flaws are detailed in Attachment V-P.1-3 and graphed in figures V.P.16 and V.P.17.

V. TROUBLESHOOTING ACTION PLAN/RESULTS (CONT.)

P. DEPOSIT FORMATION (cont.)

2. Results (cont.)

c. Eddy Current Examination (cont.)

- Steam Generator 22

Four hundred and eight-four (484) deposits (PDPs) had been classified on 432 tubes in SG 22 (Figure V.P.18). Not all deposits are associated with cracks, but 33 of 87 mid-span cracks were aligned under a deposit at the same height. Note: One of the cracks (117-40) that did not have a deposit associated with the flaw per eddy current analysis, did have a deposit build-up over the crack from approximately 40 inches above the 08H support up to the 09H support when inspected in the laboratory. The details regarding the mid-span cracks that were identified are contained in Attachment V.P.1-4.

Laboratory examination identified severe IGSCC associated with bridging deposits. The PDPs identified by eddy current were reviewed for potential indications of bridging, based upon identification of deposits on adjacent tubes at overlapping heights. The SG 22 "PDP pairs" are detailed in Attachment V.P.1-5.

PDP pairs without flaws are detailed in Attachment V.P.1-6 and graphed in figures V.P.19 and V.P.20.

Q. SLUDGE SAMPLES

Samples were obtained from SG 21 and SG 22 at the tubesheet on the hot and cold leg region and on the flow distribution plate. The samples were analyzed in the Unit 2 chemistry lab for lead (Pb), by inductive coupled plasma (ICP). Qualitative and quantitative analysis (including Pb) was performed by CE and B &W.

The sludge samples analysis identified many different elements; of specific interest are lead and hematite. The results of the analysis are provided as follows. Fe_2O_3 was present in higher amounts in SG 21 than in SG 22.

1. Lead

Initial results indicated approximately 100 ppm, from the PVNGS sample analysis.

A split of SG 21 sludge was sent to B&W, who determined that 78 ppm of lead was present.

The samples were digested in aqua regia (nitric and hydrochloric acid). PVNGS sample results were as follows:

SG 21	40	ppm Pb
SG 22	100	ppm Pb

The results from Unit 2 were comparable to that found in the sludge sample from SG 11 (obtained during Unit 1's last outage, 1R3). B&W's analysis of the sludge from SG 11 was ~78 ppm, Pb, with the majority of the material (99+%) as magnetite.

Q. SLUDGE SAMPLES (cont.)

2. Hematite

X-ray diffraction analysis results reveal that the flow distribution plate samples were consistent between the two steam generators and were typical of deposits analyzed from other plants.

ICP analysis (total concentration, ppm)

	SG 21	SG22
Cr	523	657
P	<10	<10
S	150	<100
Pb	54	N/A
Mg	102	<1
Na	133	<100
Ni	5661	5783
Al	4150	74
Mo	<100	<100
Zn	1490	268
Cu	228	3394
Fe	697,400	703,400
Si	324	61
Mn	865	764
Ca	290	46

Due to the inconsistencies seen in sludge sampling the results were inconclusive as to the full impact on steam generator tube integrity. The elements identified were, however, consistent with those found in tube deposits.

R. CHEMICAL SOURCE IDENTIFICATION STUDY

1. Action Plan

The scope of the study was to identify sources of lead, copper, sulfur, molybdenum (Pb, Cu, S, Mo) that exist or have existed on the wetted surfaces of the Unit 2 secondary systems. The specific systems to be examined are AF, AS, CD, CO, CT, ED, FT, FW, GS, MT, QH, SC, SG. The threshold of concern for the listed elements should consider a significant percentage of the element in a given component (e.g., 3%), an appreciable wetted surface area (e.g., several square inches), or a single event related intrusion that occurred during 1990 through the present.

The activities to be performed were:

a. A review of potential Pb, Cu, S, Mo sources

- Chemical use review board (CUP items)/Authorized Material List
- Consumables
- Secondary System Components
- Tools
- Secondary transport analysis
- Bulk chemicals

b. A review of Site Documentation

- Engineering Evaluation Reports
- Material Nonconformance Reports
- Site Mod/Document Change Processes
- Condition Reporting Document Reviews
- Work Orders
- Temporary Modifications
- Industry document search

c. Interviews conducted with

- Demin Operators

d. A review of Radiation Protection (RP)/As Low As Reasonably Achievable (ALARA)

R. CHEMICAL SOURCE IDENTIFICATION STUDY (cont.)

1. Action Plan (cont.)

e. Identification of Plant Component Inspection

- Pump suction strainers
- Resin trap strainers
- Condensers
- Feedwater heaters (LP and HP)
- System dead legs

2. Results

The search for contaminant sources determined the greatest sources of each element to be the following:

Sulfur	- 120 cubic feet of resin cannot be formally accounted for. The majority of the resin is transported out of the secondary system as backwash water. - For every cubic foot of resin, 10 pounds of sulfate is available. - Several pounds of sulfur could have been provided from normal erosion of the secondary piping has eroded. Molybdenum-Some eroded secondary piping contained approximately 1% molybdenum. This could have provided the source for approximately 1 pound of molybdenum. - Other secondary piping and components contain a higher percent of molybdenum; however, there is no significant evidence of erosion in these lines.
Copper	- The condenser tubesheet is 88% copper and is 2200 ft^2 in area. Depending on the corrosion rate, this could have provided the source for 5 pounds of copper.
Lead	- The heater drain and condensate pump bearings are made of graphite babbitt which could contain some lead. This could have provided the source for a very small amount of lead.

No word search of archived documents or interviews of personnel revealed any insight to the source of these elements.

FIGURE [illegible].A.1

04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

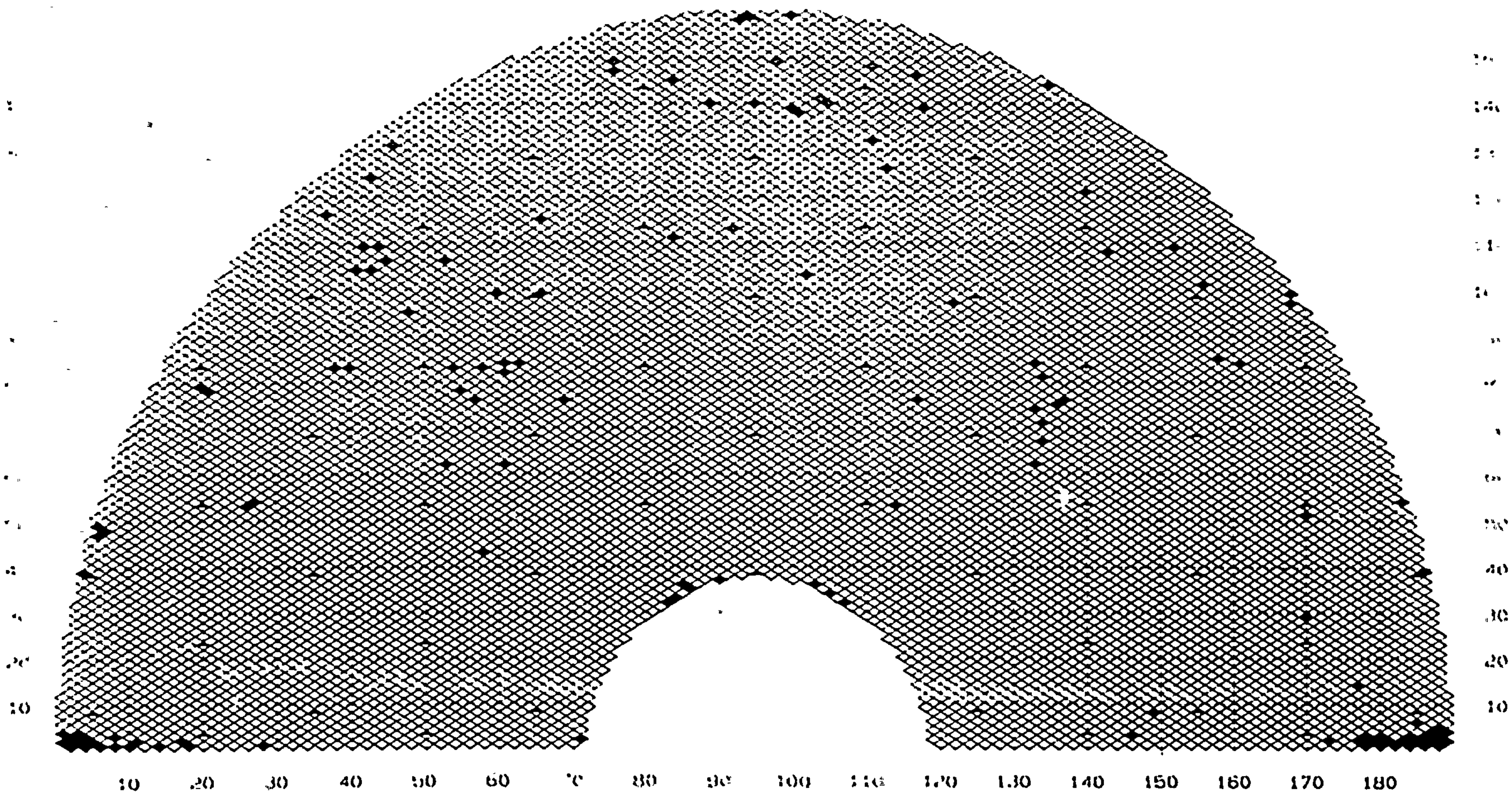
STEAM GENERATOR: 21

SG 21 Upper Bundle Axial Indications

DATE: 07/15/93
TIME: 10:05:37

LOCATION 03H+ 2.0 TO VS4
CRITERIA SAI, MAI

STAYS



CONAM NUCLEAR, INC. BW

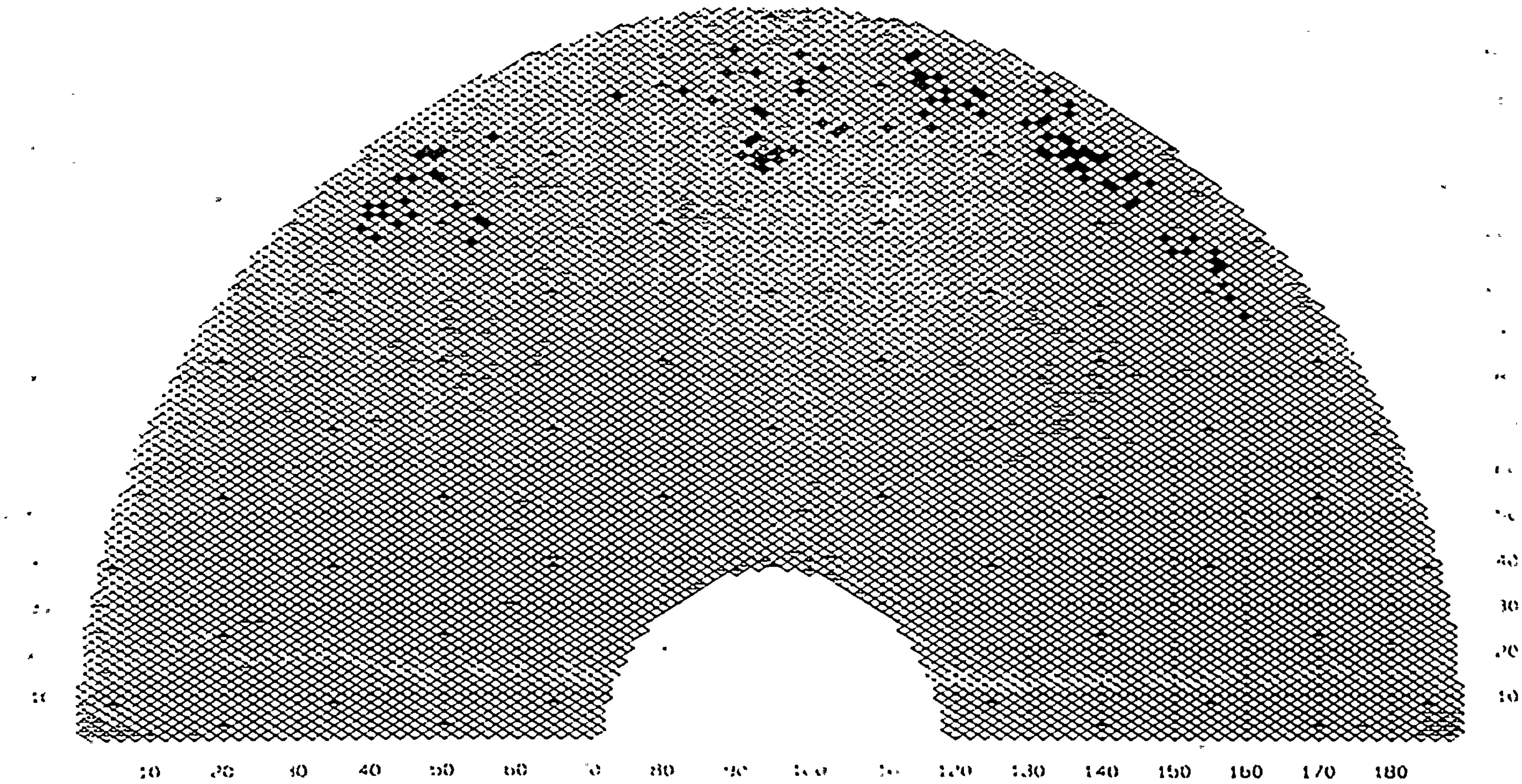
FIGURE [illegible].2

04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

STEAM GENERATOR: 22 | SG 22 Upper Bundle Axial Indications | DATE: 07/15/93
TIME: 14:18:27

LOCATION: 03H+ 2.0 TO VS4
CRITERIA: SAI.MAI

STAYS



CONAM NUCLEAR, INC BW

FIGURE V.A.3

Steam Generator 21 and 22
MRPC Arc Inspection Pattern

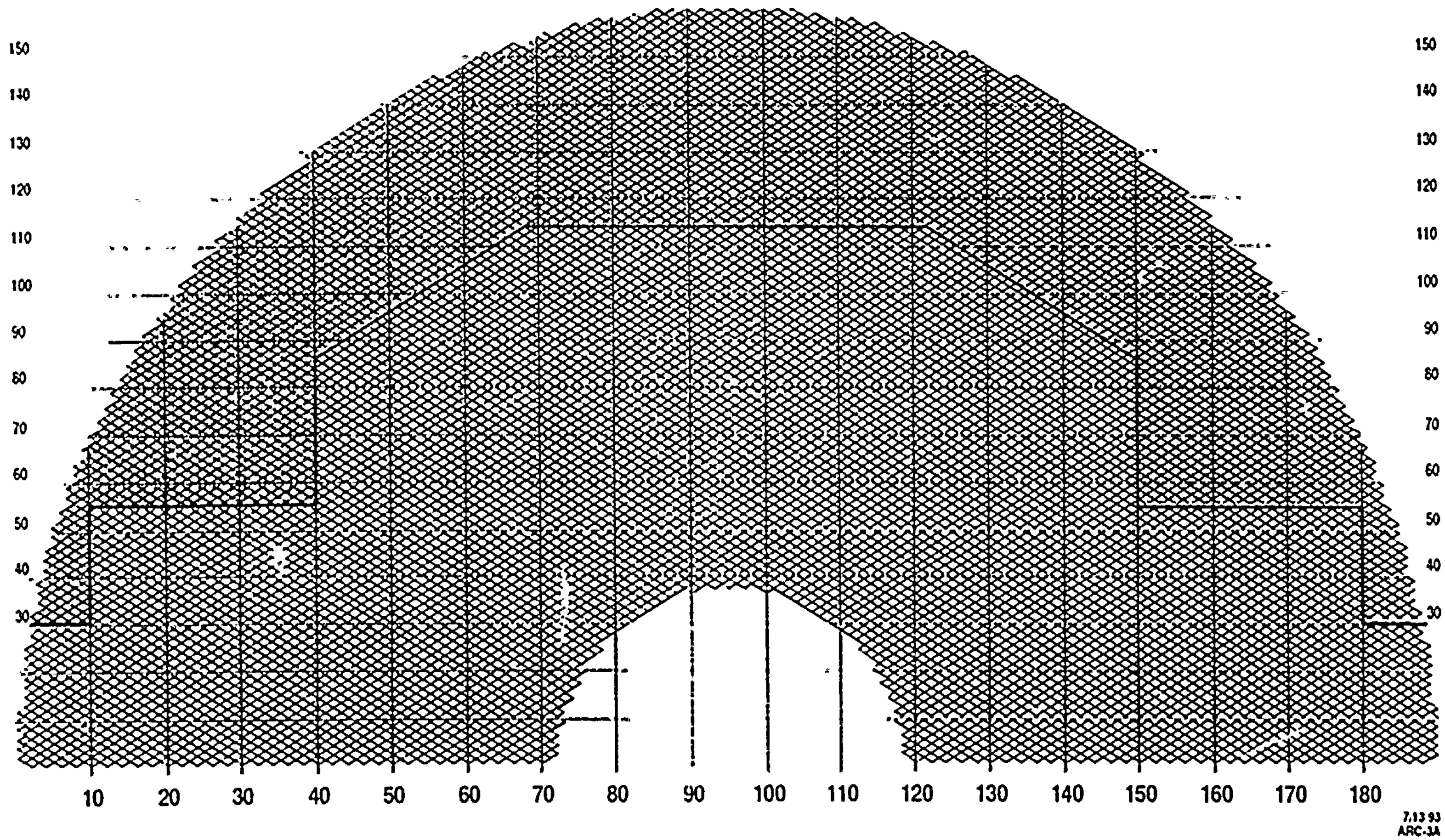


FIGURE [illegible].4

04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

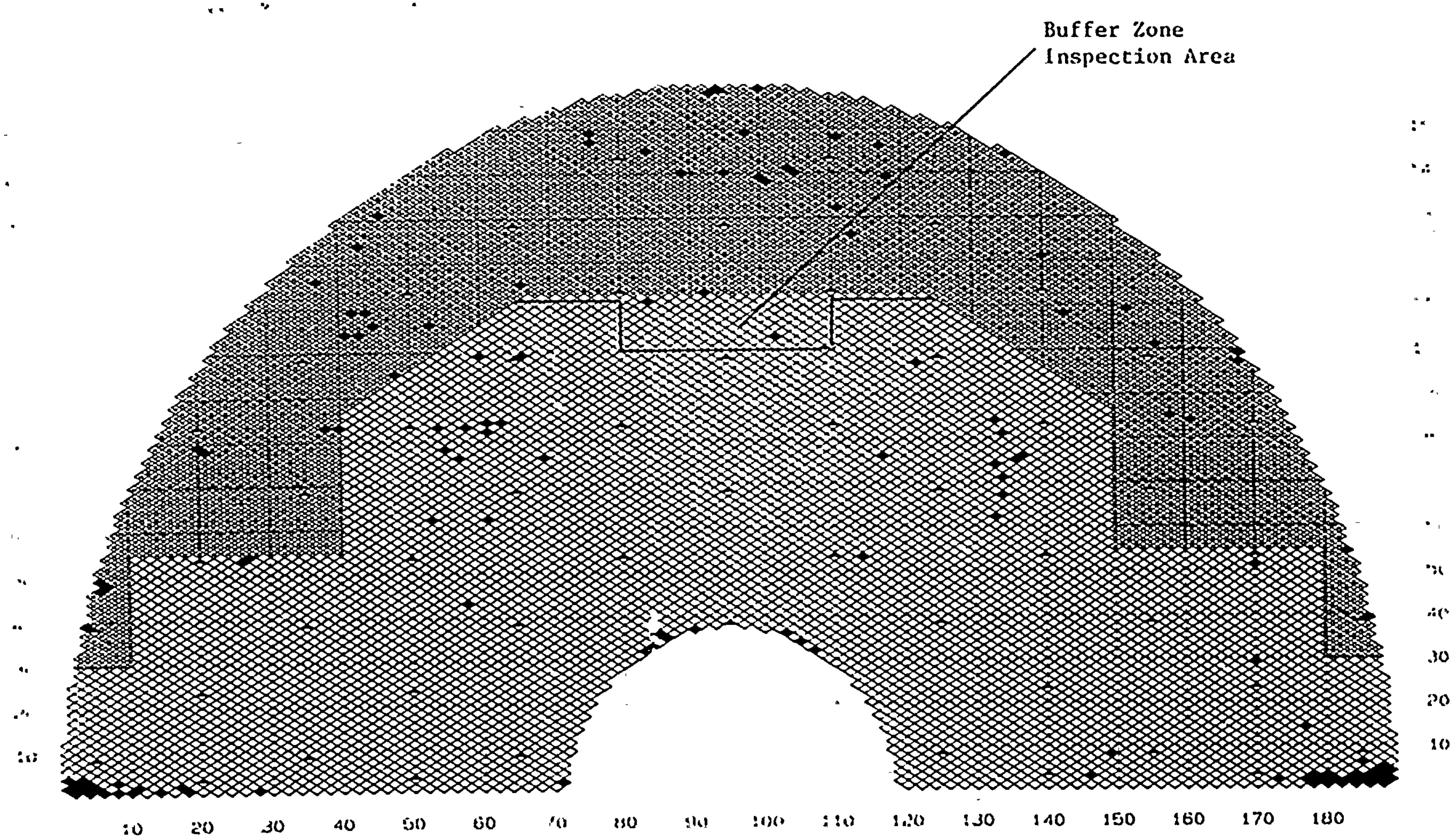
STEAM GENERATOR: 21

SG 21 Upper Bundle Indications Compared to Inspection Program

DATE: 07/15/93
TIME: 08:59:56

LOCATION: ALL
CRITERIA: SAI,MAI IN THE ARC AREA

STAYS



CONAM NUCLEAR, INC. BW

FIGU .A.5

04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

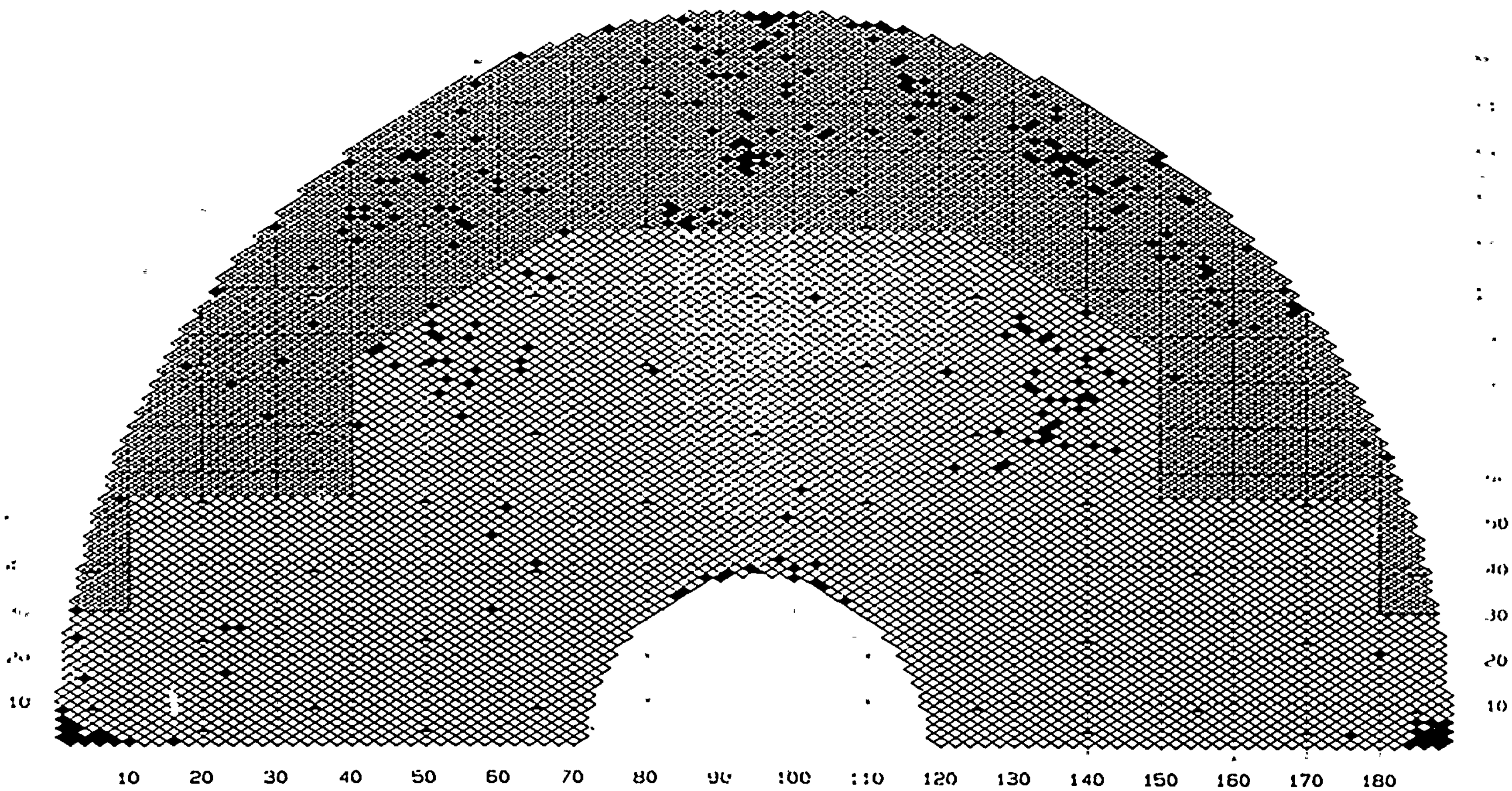
STEAM GENERATOR: 22
LOCATION: ALL
CRITERIA: SAI, MAI

SC 22 Upper Bundle Indications Compared to Inspection Program

DATE: 07/15/93
TIME: 11:24:50

STAYS ▲

195 ◆ MAI ◆ SAI 102 ◆



CONAM NUCLEAR, INC. BW

FIGUR[illegible]A.6

04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

STEAM GENERATOR: 21

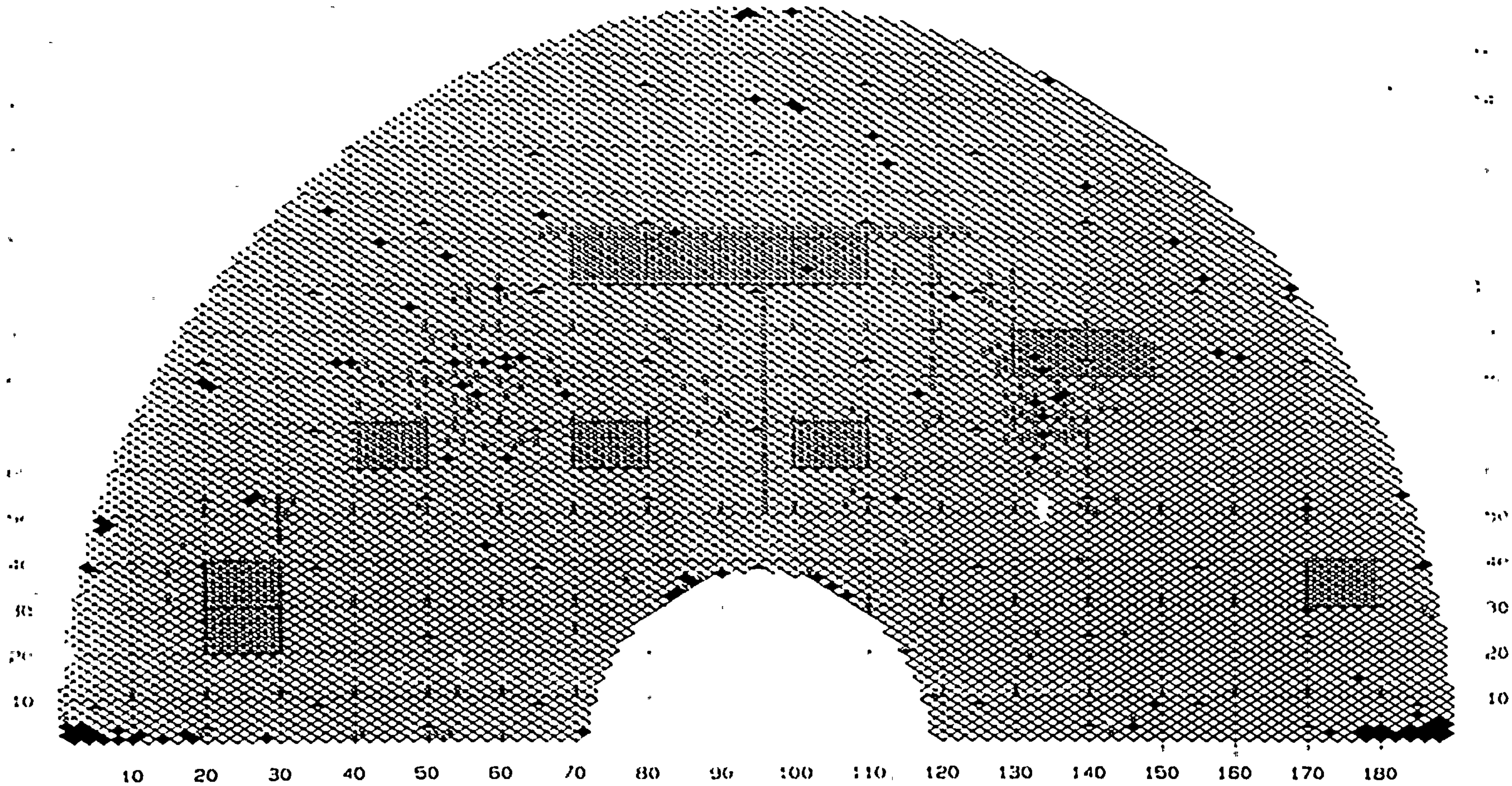
SG 21 Tubes Inspected in Vertical Legs Outside the Arc

DATE: 07/15/93
TIME: 09:44:36

LOCATION: ALL
CRITERIA: TUBES PROBED NARC BW1 - 02H

STAYS ▲

NUMBER 114 ◆



CONAM NUCLEAR, INC. BW

FIGURE V.A.7

04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

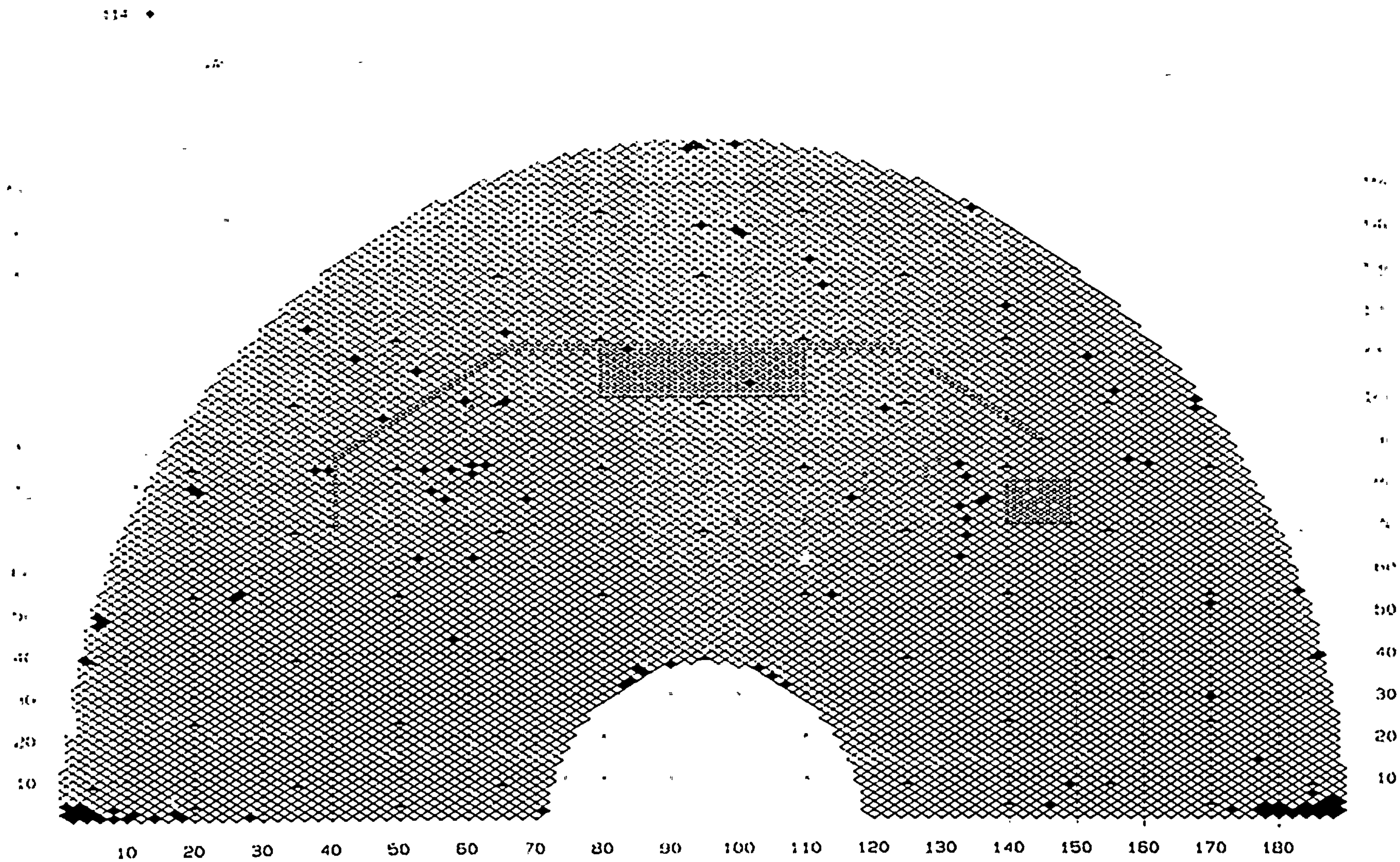
STEAM GENERATOR: 21

SG 21 Tube Bends Inspected Outside the Arc

DATE: 07/15/93
TIME: 09:28:20

LOCATION: ALL
CRITERIA: TUBES PROBED NARC BW1 - 1st VERTICAL STRAP

STAYS ▲



CONAM NUCLEAR, INC. BW

FIG[illegible]V.A. 8

04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

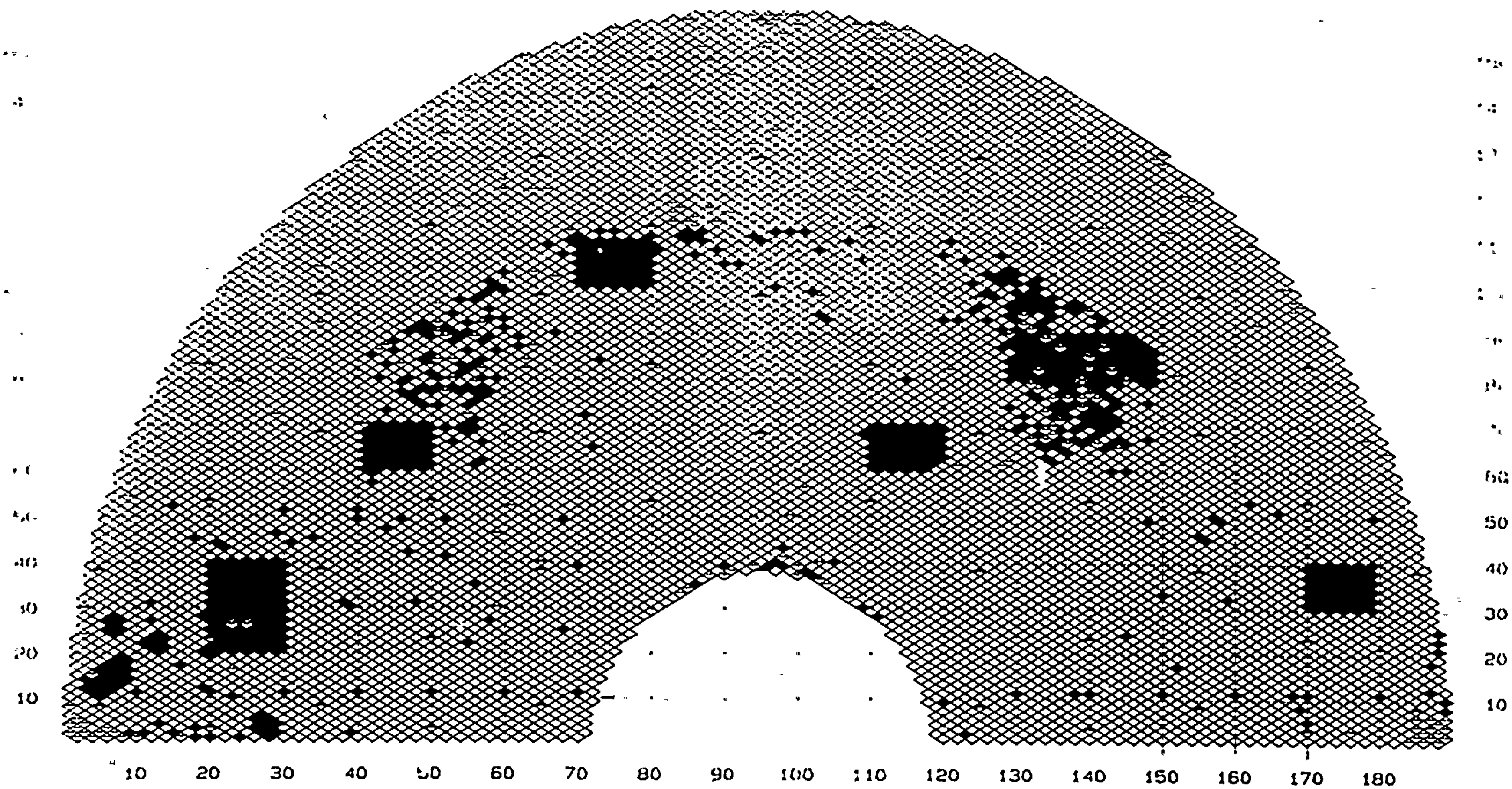
STEAM GENERATOR: 22

SG 22 Tubes Inspected in Vertical Legs Outside the Arc

DATE: 07/15/93
TIME: 14:39:46

LOCATION: ALL
CRITERIA: TUBES PROBED NARC BW1 - 02H

STAYS



CONAM NUCLEAR, INC. BW

FIGU[illegible].A.9

04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

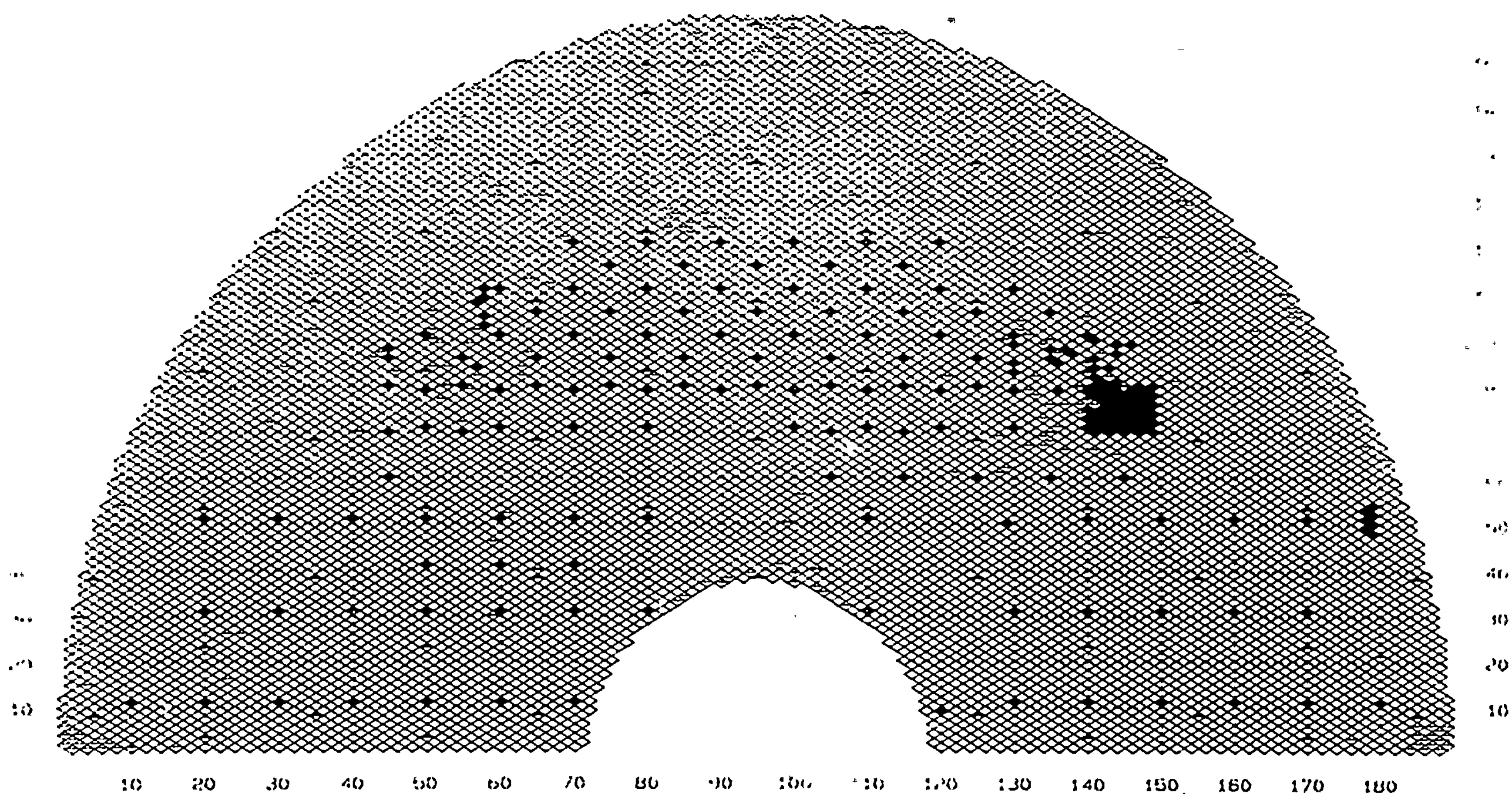
STEAM GENERATOR: 22

SG 22 Tube Bends Inspected Outside the Arc

DATE: 07/15/93
TIME: 14:36:17

LOCATION: ALL
CRITERIA: TUBES PROBED NARC BW1 - 1ST VERTICAL STRAP

STAYS



CONAM NUCLEAR, INC. BW

FIGU[illegible]A.10

04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

STEAM GENERATOR: 21

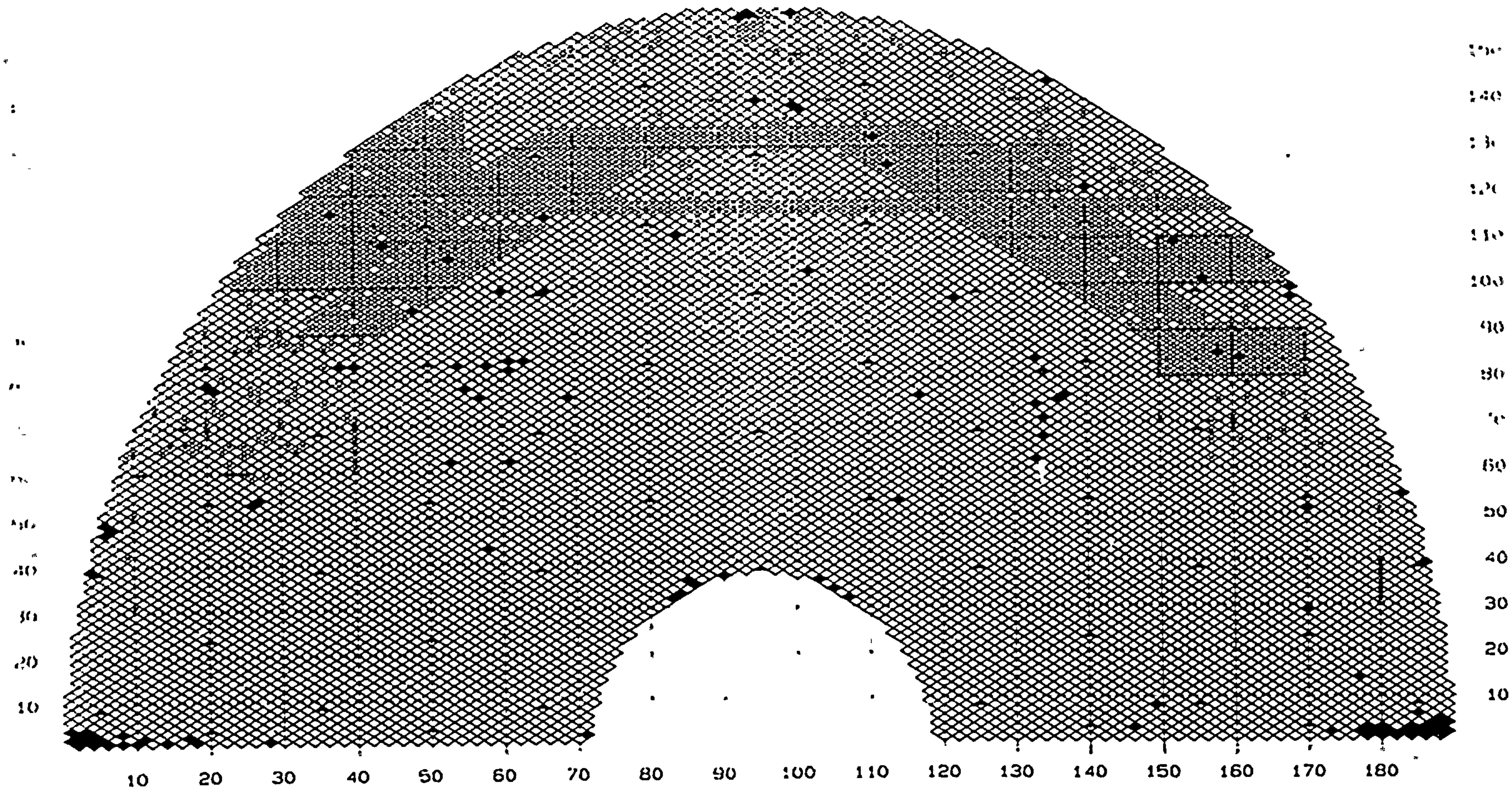
DATE: 07/09/93
TIME: 12: 19: 15

LOCATION: ALL
CRITERIA: TUBES EVALUATED BELOW THE ARC ELEVATION

STAYS ▲

PLUGGED 114 ◆

EVALUATED [illegible] ▪



CONAM NUCLEAR, INC. BW

FIGURE 11

04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

STEAM GENERATOR: 22

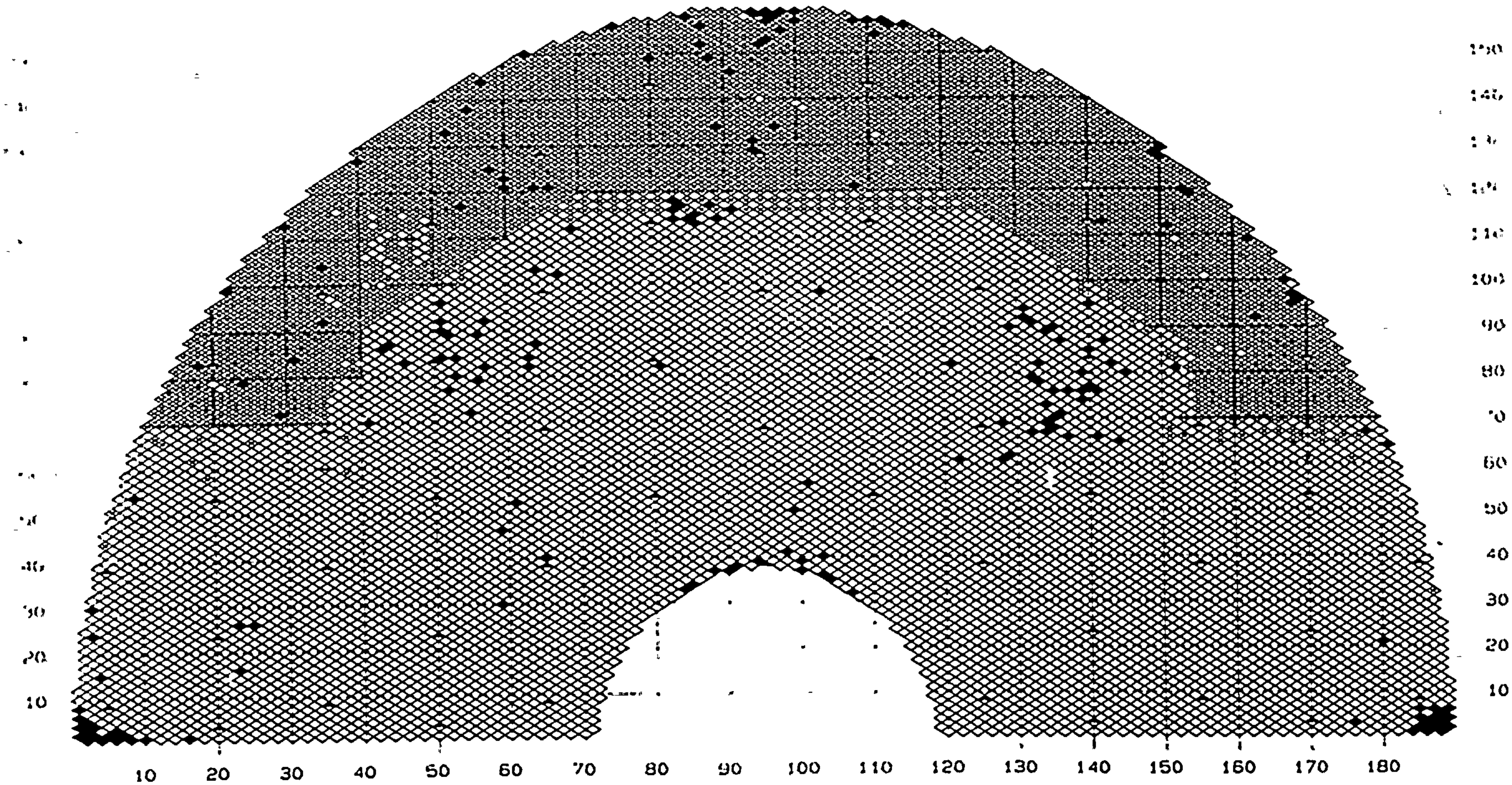
DATE: 07/09/93
TIME: 14:52:13

LOCATION: ALL
CRITERIA: TUBES EVALUATED BELOW THE ARC ELEVATION

STAYS

PLUGGED 195

EVAL COMPLETED 3070



CONAM NUCLEAR, INC. BW

FIGURE V.A.12

7/10/93 Data

Steam Generator 21 and 22

Batwing-1 to Vertical U-Bend Tangent Midspan Defects

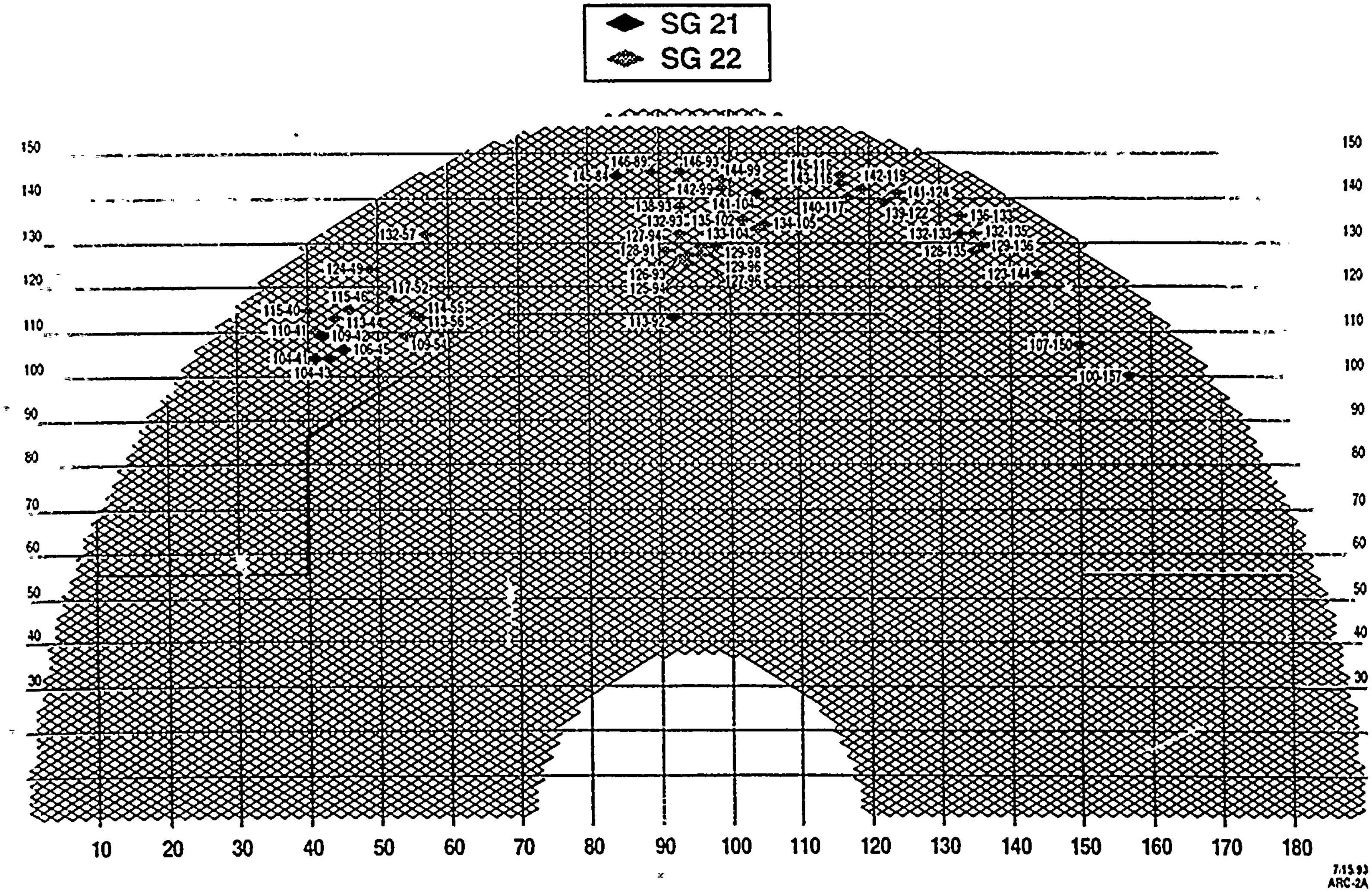


FIGURE V.A. 13

7/10/93 Data

Steam Generator 21 and 22

Horizontal U-Bend Tangent Midspan Defects

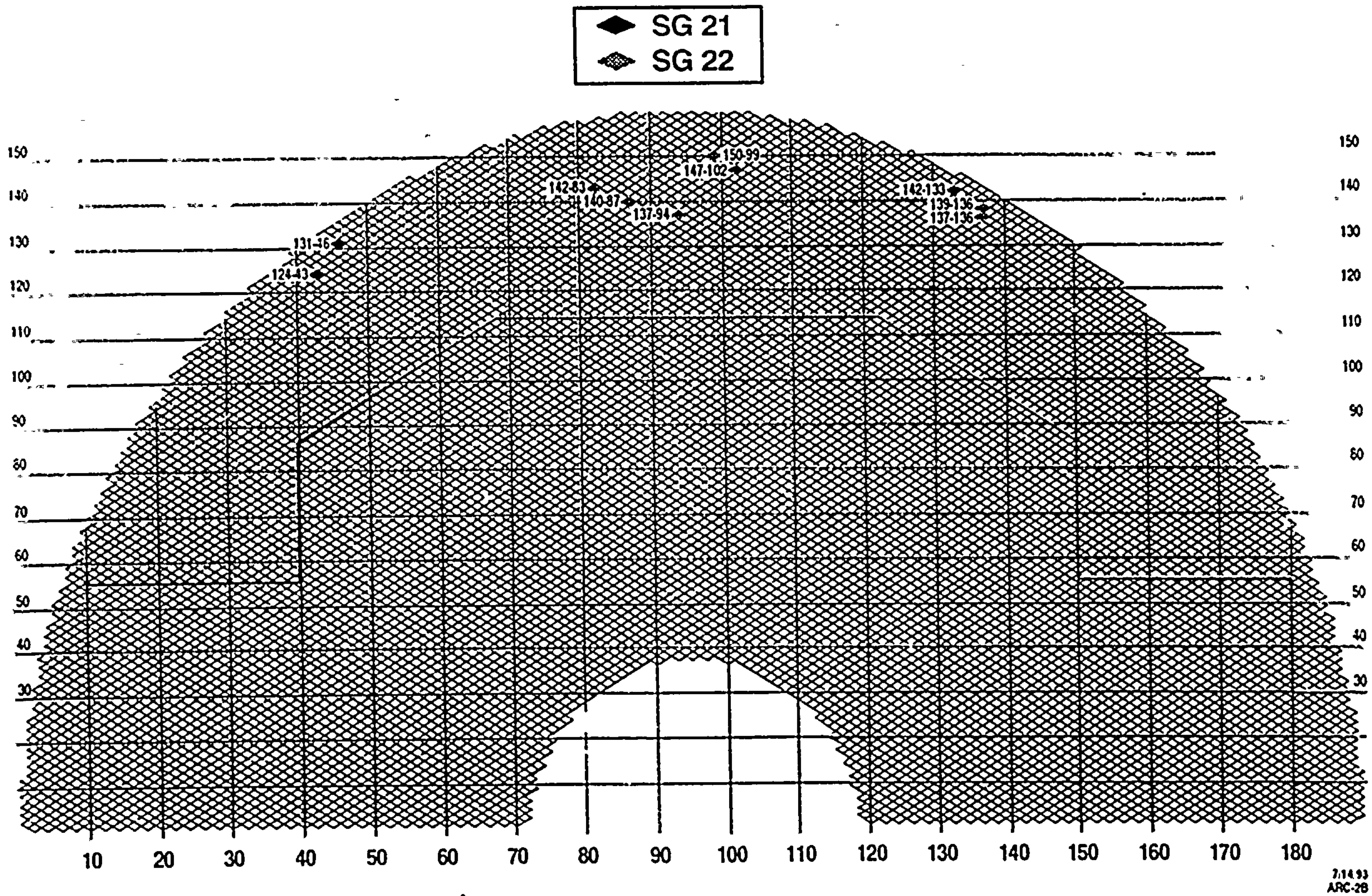


FIGURE V.A.14

04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

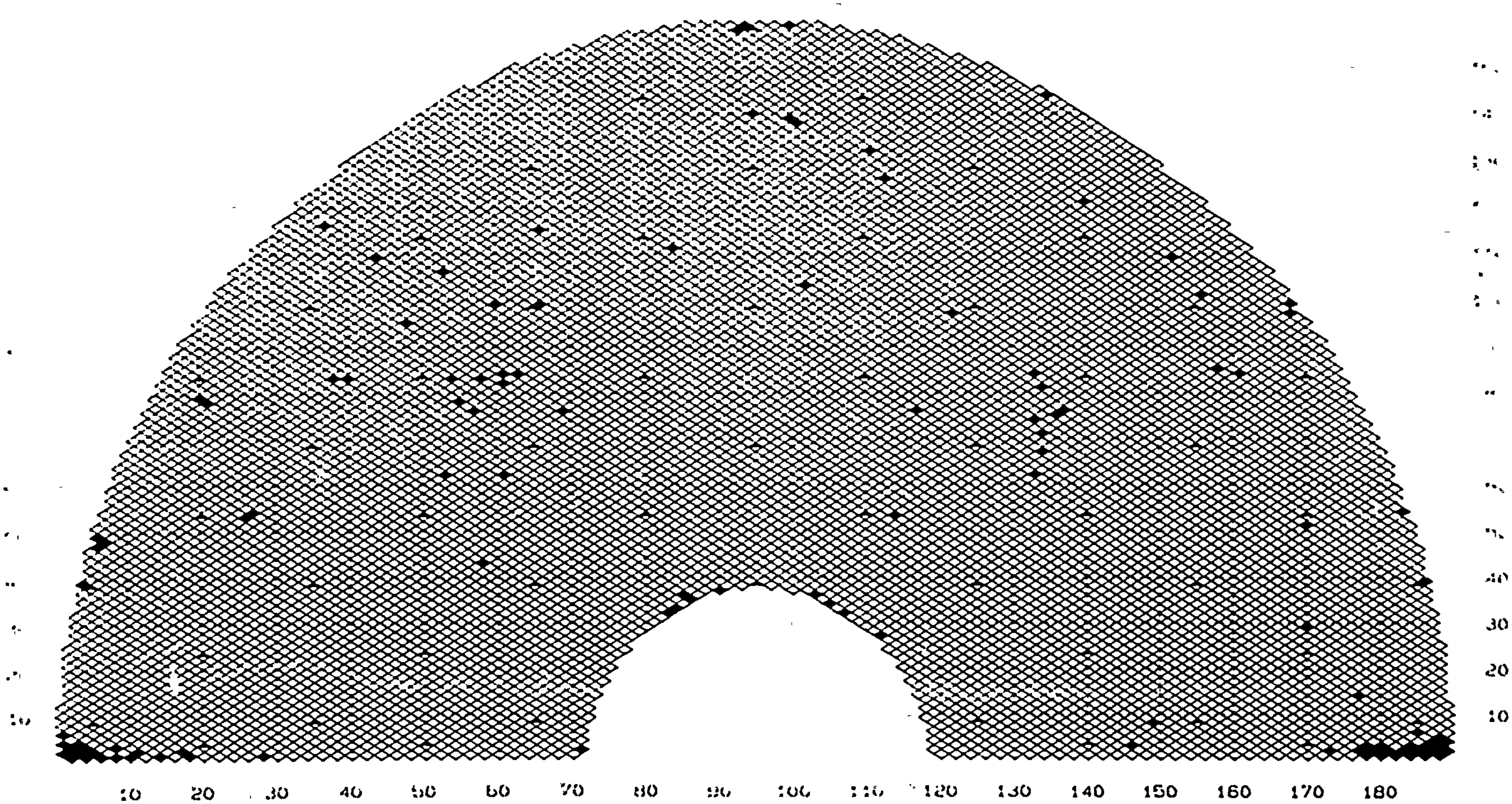
STEAM GENERATOR: 21

DATE: 07/08/93
TIME: 12:55:03

LOCATION: TEH TO 03H- 2.0
CRITERIA: SAT.MAI

STAYS ▲

PLUGGED 114 ◆



CONAM NUCLEAR, INC. BW

FIGURE V.A.15

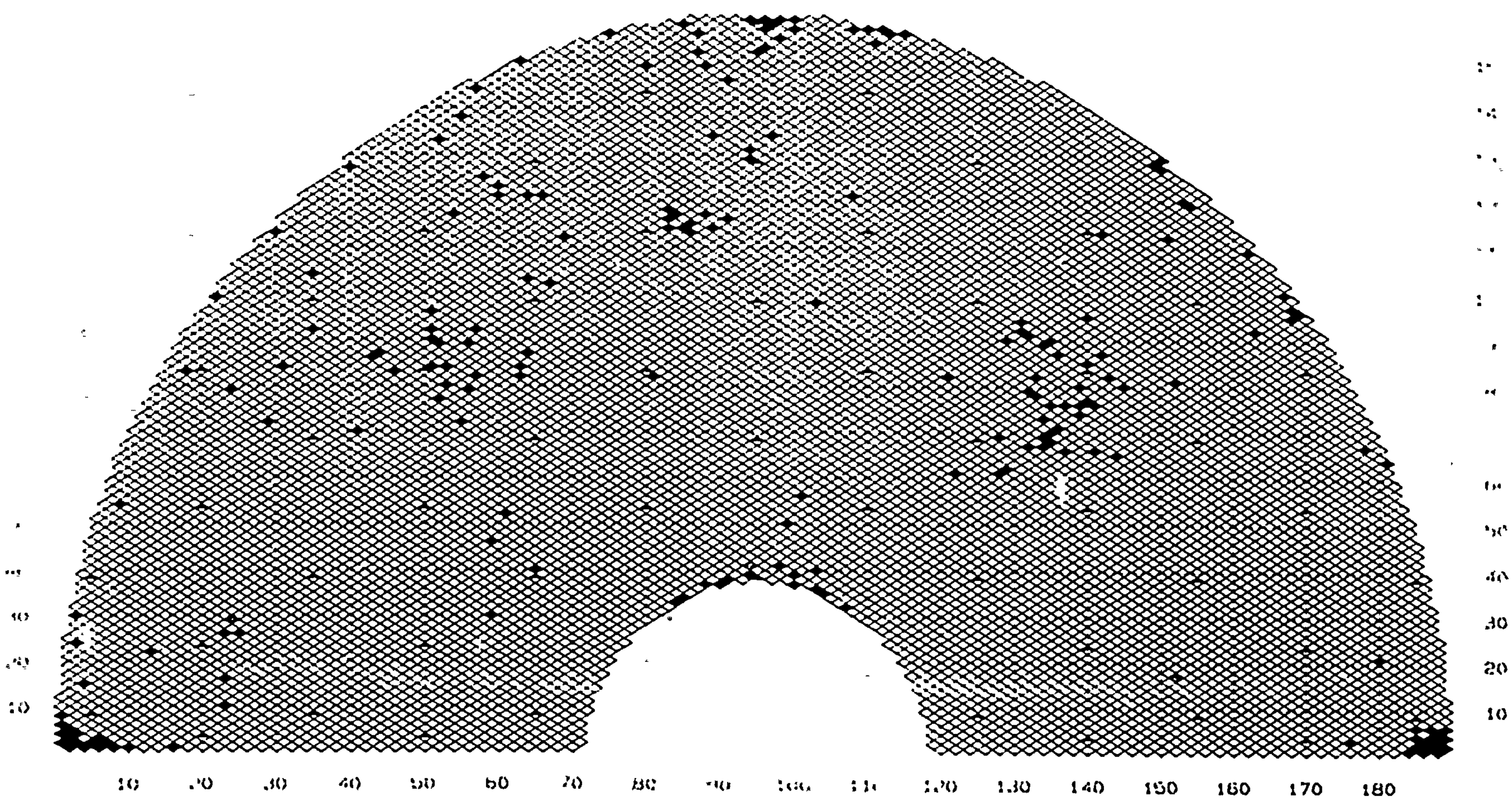
04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

STEAM GENERATOR: 22

LOCATION: TEH TO 03H- 2.0
CRITERIA: SAT, MAI

DATE: 07/08/93
TIME: 12:47:06

STAYS



CONAM NUCLEAR, INC. BW

Table V.A.1

STEAM GENERATOR 21

MRPC INSPECTION SUMMARY

7-14-93

	ESTIMATED INSPECTIONS IN ARC AREA	ESTIMATED INSPECTIONS OUTSIDE ARC
BW1-1st VS	3999	370
08H-BW1	3966	691
07H-08H	1154	577
07H	2075	624
06H	123	494
05H	106	201
04H	108	109
03H	127	109
02H	124	142
01H	652	327
TSH	696	242

Table V.A.2

STEAM GENERATOR 22
MRPC INSPECTION SUMMARY

7-14-93

	ESTIMATED INSPECTIONS IN ARC AREA	ESTIMATED INSPECTIONS OUTSIDE ARC
BW1-1st VS	3677	245
08H-BW1	3775	613
07H-08H	642	453
07H	3458	514
06H	242	126
05H	228	114
04H	244	114
03H	234	115
02H	235	116
01H	753	334
TSH	579	224

Table V.A.3

SG 21 AXIAL CRACK INDICATIONS BY ELEVATION

SG 21	NBI	NQI	OTHER	TOTAL INDICATIONS
TSH	0	1	1	2
01H	0	0	0	0
02H	0	0	0	0
03H	0	0	0	0
04H	0	0	0	0
05H	0	0	0	0
06H	0	0	0	0
07H	0	0	0	0
08H	0	0	1	1
08H-09H	1	0	0	1
09H	1	0	0	1
09H-BW1	4	2	0	6
BW1	2	0	0	2
U-bend (Vert.)	8	0	0	8
U-bend (Hori.)	0	1	0	1
VS	0	0	0	1
Totals	16	4	5	23

NBI = No Bobbin Indication, Detected By MRPC Only
NQI = Non-Quantifiable Indication (but detectable by bobbin)
Other = Other Bobbin Calls (depth quantifiable or otherwise detectable by bobbin)

NOTE: In SG 21, twenty (20) tubes contain the 23 cracks listed in Table 1. Seventeen (17) tubes have only one axial crack per tube; three (3) tubes have multiple indications of two cracks per tube.

Table V.A.4

SG 22 AXIAL CRACK INDICATIONS BY ELEVATION

SG 21	NBI	NQI	OTHER	TOTAL INDICATIONS
TSH	0	0	1	1
01H	0	0	4	4
02H	0	0	0	0
03H	0	0	0	0
04H	0	0	0	0
05H	0	0	1	1
06H	0	0	0	0
07H	0	0	2	2
08H	4	0	11	15
08H-09H	11	5	4	20
09H	5	0	11	16
09H-BW1	10	4	3	17
BW1	10	4	3	17
U-bend (Vert.)	38	6	2	46
U-bend (Hori.)	8	0	0	8
VS	0	0	0	0
Totals	81	21	40	142

NBI = No Bobbin Indication, Detected By MRPC Only
NQI = Non-Quantifiable Indication (but detectable by bobbin)
Other = Other Bobbin Calls (depth quantifiable or otherwise detectable by bobbin)

NOTE: In SG 22, 109 tubes contain the 142 cracks listed in Table VII.4. Eighty-seven (87) tubes have only one axial indication. Twenty-two (22) tubes have multiple indications. Fourteen (14) tubes have two cracks per tube, six (6) tubes have three cracks per tube and one (1) tube has four cracks per tube.

SG 21 AXIAL INDICATION SUMMARY

TABLE V.A.5

7/15/93

ROW	LINE	LOCATION		LENGTH	BOBBIN INDICATION	DEPOSIT	
6	1	TSH	-.93	.14	NQI	NO	TSH
104	41	BW1	+4.67	.26	NBI	YES	MID
109	42	08H	+34.35	6.96	NBI	YES	MID
		BW1	+3.73	.49	NBI	YES	MID
104	43	BW1	+3.76	.98	NBI	YES	MID
124	43	VS1	-.94	.26	41%	NO	VS1
106	45	BW1	-.77	.38	NBI	NO	MID
		BW1	+2.74	1.16	NBI	YES	MID
131	46	BW1	+18.81	.41	NQI	NO	MID
147	76	09H	+25.44	.56	NBI	YES	MID
149	76	09H	+24.92	.41	NQI	YES	MID
145	84	BW1	+4.68	.49	NBI	NO	MID
140	89	09H	+23.34	.41	NQI	YES	MID
113	92	BW1	+3.39	1.01	NBI	YES	MID
149	98	BW1	+1.09	.19	NBI	NO	BW1
141	104	BW1	+3.10	.31	NBI	NO	MID
140	105	BW1	-1.51	.10	81%	NO	BW1
148	111	09H	+27.83	.50	NBI	YES	MID
		09H	+33.90	.40	NBI	YES	MID
27	112	TSH	-.88	.35	7%	NO	TSH
146	117	09H	+.20	.50	NBI	NO	EGG
139	118	09H	+24.90	.20	NBI	YES	MID
108	143	08H	+.81	.23	DSI	NO	EGG

SG22 AXIAL INDICATION SUMMARY

TABLE V.A.6

7/15/93

ROW	LINE	LOCATION		LENGTH	BOBBIN INDICATION	DEPOSIT	
*22	13	01H	-.29	.19	52%	NO	01H
10	23	01H	+.04	.36	30%	NO	01H
*29	24	01H	-.30	.20	DSI	NO	01H
112	39	08H	+29.38	.72	NQI	YES	MID
115	40	08H	+40.62	.38	NQI	YES	MID
		BW1	+3.63	2.17	NBI	NO	MID
*117	40	08H	+40.89	.21	NBI	NO	MID
110	41	BW1	+5.07	.53	NBI	YES	MID
115	42	08H	+39.44	.16	NQI	YES	MID
117	42	08H	+49.08	.32	46%	YES	MID
		08H	+41.88	.32	NQI	YES	MID
113	44	BW1	+4.12	.78	NDD/NQI	YES	MID
123	44	08H	+.25	.55	71%	NO	EGG
118	45	09H	-.77	.77	DSI	NO	EGG
115	46	BW1	+5.28	.82	NQI	NO	MID
123	46	08H	-.38	.18	DSI	NO	EGG
		09H	+.21	.19	NBI	NO	EGG
128	47	08H	+.38	.55	82%	NO	EGG
129	48	08H	+.48	.64	DSI	NO	EGG
124	49	BW1	+8.71	.99	NBI	NO	MID
128	49	08H	+.65	.31	69%	NO	EGG
		BW1	-1.59	.43	NBI	NO	BW1
123	50	09H	+.62	.18	55%	NO	EGG
129	50	08H	+.62	.19	DSI	NO	EGG
117	52	BW1	+8.84	.102	NBI	NO	MID
109	54	BW1	+4.57	.83	NBI	NO	MID
114	55	BW1	+4.22	.99	NBI	YES	MID
113	56	BW1	+3.69	.71	NBI	YES	MID
132	57	BW1	+.05	.24	NQI	YES	MID
141	74	BW1	+.23	.89	NBI	NO	BW1
142	83	BW1	+18.35	2.75	NBI	NO	MID
140	87	BW1	+19.24	.96	NBI	NO	MID
146	89	BW1	+2.74	.96	NQI	YES	MID
151	90	05H	+.76	.24	73%	NO	EGG
128	91	BW1	+6.61	1.65	NBI	YES	MID
131	92	09H	+16.14	.36	NBI	NO	MID
126	93	BW1	+7.15	1.05	NBI	NO	MID

TABLE V.A.6 CONTINUED)

ROW	LINE	LOCATION		LENGTH	BOBBIN INDICATION	DEPOSIT	
128	93	BW1	+.80	.24	NQI	NO	BW1
132	93	BW1	+7.90	.60	NBI	NO	MID
138	93	BW1	+2.79	2.41	NBI	NO	MID
146	93	BW1	+3.61	.39	NBI	YES	MID
41	94	TEH	+1.99	.51	99%	NO	TSH
125	94	08H	+24.69	1.31	NBI	YES	MID
		08H	+30.47	1.43	NBI	YES	MID
		08H	+38.55	1.25	NBI	NO	MID
		BW1	+6.64	.56	NBI	NO	MID
127	94	BW1	+5.91	2.39	NBI	NO	MID
137	94	BW1	+18.86	.44	NBI	NO	MID
127	96	08H	+13.96	.94	NBI	NO	MID
		08H	+33.46	.54	NBI	NO	MID
		08H	+39.66	.24	NBI	NO	MID
		08H	+40.98	.62	NBI	NO	MID
		BW1	+2.35	.45	NBI	NO	MID
		BW1	+3.92	2.38	NBI	NO	MID
129	96	BW1	+2.86	.54	NQI	NO	MID
		BW1	+5.80	1.80	NBI	NO	MID
129	98	BW1	+4.08	1.22	NBI	YES	MID
		BW1	+6.62	.78	NBI	YES	MID
142	99	BW1	+3.53	.57	NBI	NO	MID
144	99	BW1	+4.55	2.55	NBI	NO	MID
150	99	BW1	+18.38	1.27	NBI	NO	MID
135	102	BW1	+1.45	.55	NBI	NO	MID
		BW1	+6.19	.41	NBI	NO	MID
147	102	BW1	+7.83	3.07	NBI	YES	MID
		BW1	+13.45	.45	NBI	YES	MID
		BW1	+18.88	.92	NBI	YES	MID
133	104	BW1	+1.89	.71	NBI	NO	MID
134	105	BW1	+1.10	1.00	NBI	NO	MID
134	111	09H	+20.47	.63	NDD/NQI	YES	MID
149	114	08H	+.27	.13	NBI	NO	EGG
144	115	09H	+25.89	.31	NBI	YES	MID
		09H	+27.70	.50	NQI	YES	MID
		09H	+32.34	.56	NBI	YES	MID
146	115	09H	+22.95	7.35	NQI	YES	MID
150	115	08H	+.65	.25	69%	NO	EGG
		09H	+24.46	7.24	NQI	YES	MID
137	116	BW1	-1.17	2.47	NDD/NQI	NO	BW1
143	116	BW1	+3.5	.50	NBI	NO	MID
145	116	BW1	+6.42	.28	NBI	NO	MID

TABLE V.A.6(CONTINUED)

ROW	LINE	LOCATION		LENGTH	BOBBIN INDICATION	DEPOSIT	
134	117	09H	+14.20	1.19	NBI	YES	MID
140	117	BW1	+2.63	.47	NBI	YES	MID
145	118	09H	+28.91	1.09	NQI	YES	MID
140	119	09H	+22.99	.21	64%	YES	MID
142	119	09H	+20.75	3.95	NQI	YES	MID
		BW1	+4.94	.26	NBI	NO	MID
139	122	BW1	+3.77	.43	NBI	YES	MID
142	123	09H	+.65	.45	NBI	NO	EGG
137	124	BW1	+.57	.33	73%	NO	BW1
141	124	09H	-.46	.56	NBI	NO	EGG
		09H	+.76	.14	NBI	NO	EGG
		BW1	+2.86	.58	NBI	YES	MID
135	130	08H	+.58	.22	NBI	NO	EGG
129	132	09H	+.24	.96	67%	NO	EGG
		BW1	+.66	.34	NDD/NQI	NO	BW1
135	132	08H	+.24	.36	NBI	NO	EGG
		BW1	+1.72	.28	NBI	NO	BW1
128	133	09H	+.57	.53	84%	NO	EGG
132	133	BW1	+3.60	.90	NBI	NO	MID
136	133	BW1	+7.59	.81	NBI	NO	MID
142	133	BW1	+15.53	.17	NBI	NO	MID
128	135	09H	-.70	.38	23%	NO	EGG
		09H	+.18	.52	79%	NO	EGG
		BW1	+5.39	.88	NQI	NO	MID
132	135	BW1	+6.92	.39	23%	NO	MID
125	136	09H	+.04	.76	57%	NO	EGG
129	136	BW1	+6.96	.74	NBI	NO	MID
131	136	09H	+17.87	.13	NBI	YES	MID
137	136	BW1	+16.93	.77	NBI	NO	MID
139	136	BW1	+15.18	.32	NBI	NO	MID
126	137	BW1	-1.73	.13	NBI	NO	BW1
128	137	08H	+.25	.65	55%	NO	EGG
123	138	BW1	-1.13	.23	NBI	NO	BW1
125	138	08H	+.06	.44	99%	NO	EGG
129	138	BW1	+1.61	.19	NBI	NO	BW1
128	139	08H	+.68	.22	NBI	NO	EGG
127	140	07H	+.30	.30	77%	NO	EGG
		07H	+.21	.41	39%	NO	EGG
122	141	09H	+.53	.30	NBI	NO	EGG
128	141	08H	+.38	.64	88%	NO	EGG
121	142	09H	+.02	.28	71%	NO	EGG
		BW1	-.88	.28	NBI	NO	BW1
*117	144	08H	+34.34	9.16	100%	YES	MID
		08H	+43.92	.47	62%	NO	EGG
		BW1	-1.66	1.16	96%	NO	BW1

TABLE V.A.6(CONTINUED)

ROW	LINE	LOCATION		LENGTH	BOBBIN INDICATION	DEPOSIT	
123	144	BW1	+5.60	.60	NBI	NO	MID
118	145	09H	-2.19	.19	DSI	NO	EGG
124	145	BW1	+1.11	.79	81%	NO	BW1
122	147	BW1	+1.26	.24	NBI	NO	BW1
110	149	08H	+.08	.62	85%	NO	EGG
		BW1	+.61	.09	NBI	NO	BW1
107	150	BW1	+3.57	.31	NBI	YES	MID
17	*152*	*01H*	*-.3*	*.2*	*31%*	*1991DATA*	*01H*
107	152	LB1	+.00	.2	NDD/NQI	NO	BW1
110	153	07H	+.39	.41	NDD/DSI	NO	EGG
*103	156	08H	+16.39	2.83	NBI	YES	MID
*105	156	08H	+19.64	1.36	NBI	YES	MID
		08H	+21.54	4.08	84%	YES	MID
		08H	+26.26	4.39	85%	YES	MID
107	156	08H	+24.68	.12	NQI	YES	MID
100	157	BW1	+2.13	1.17	81%	YES	MID
104	157	08H	+24.59	3.41	85%	YES	MID
97	158	BW1	-1.93	.13	NBI	NO	BW1
93	160	08H	+19.11	.19	NBI	YES	MID

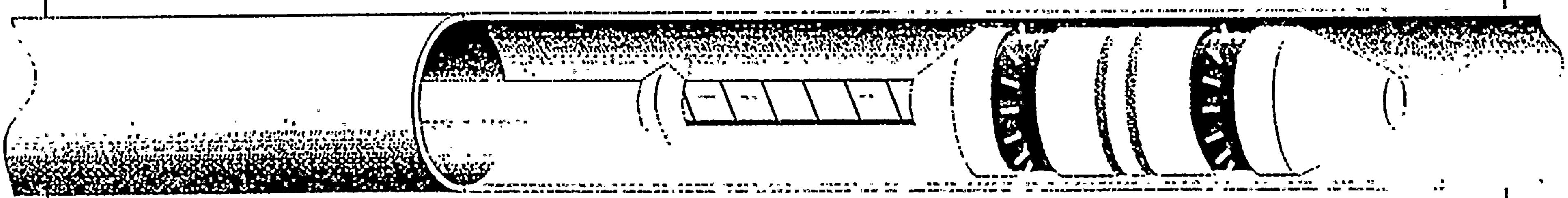
*PULL TUBES

EDDY CURRENT TECHNIQUES

BOBBIN COIL TECHNIQUE

PURPOSE: Volumetric examination to satisfy tech specifications, ASME, and to detect any and all (possible) degradation.

Calibration: ASME and wear standard



Typical Probe: Probe size: .610" HF

graphic design by Jim Pire

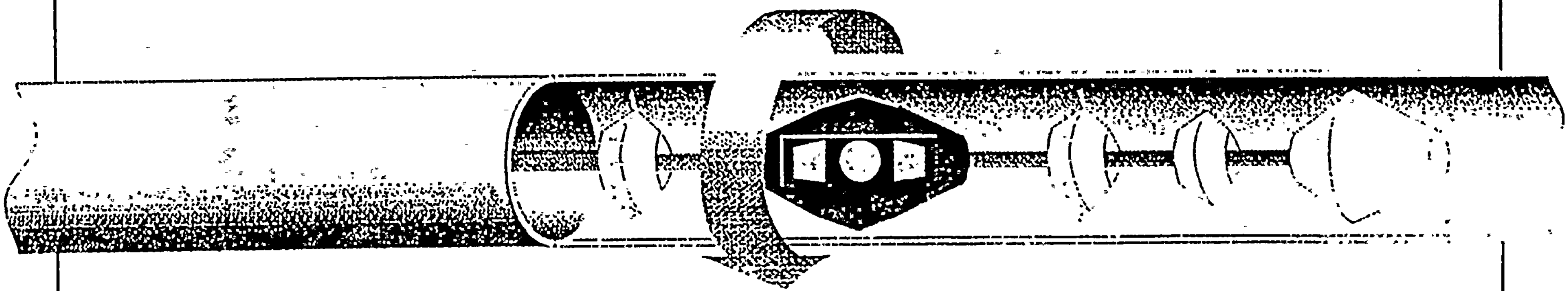
FIGURE V.B.1

EDDY CURRENT TECHNIQUES

ROTATING PANCAKE COILS

PURPOSE: Volumetric examination to verify bobbin detection, to characterize degradation, and to detect circumferential cracks.

In addition, several tubes were detected with axial (crack) indications using RPC that were not detected with bobbin.



Straight	3-COIL	.610"	U OR Square	1 COIL or 3 COIL	.580"

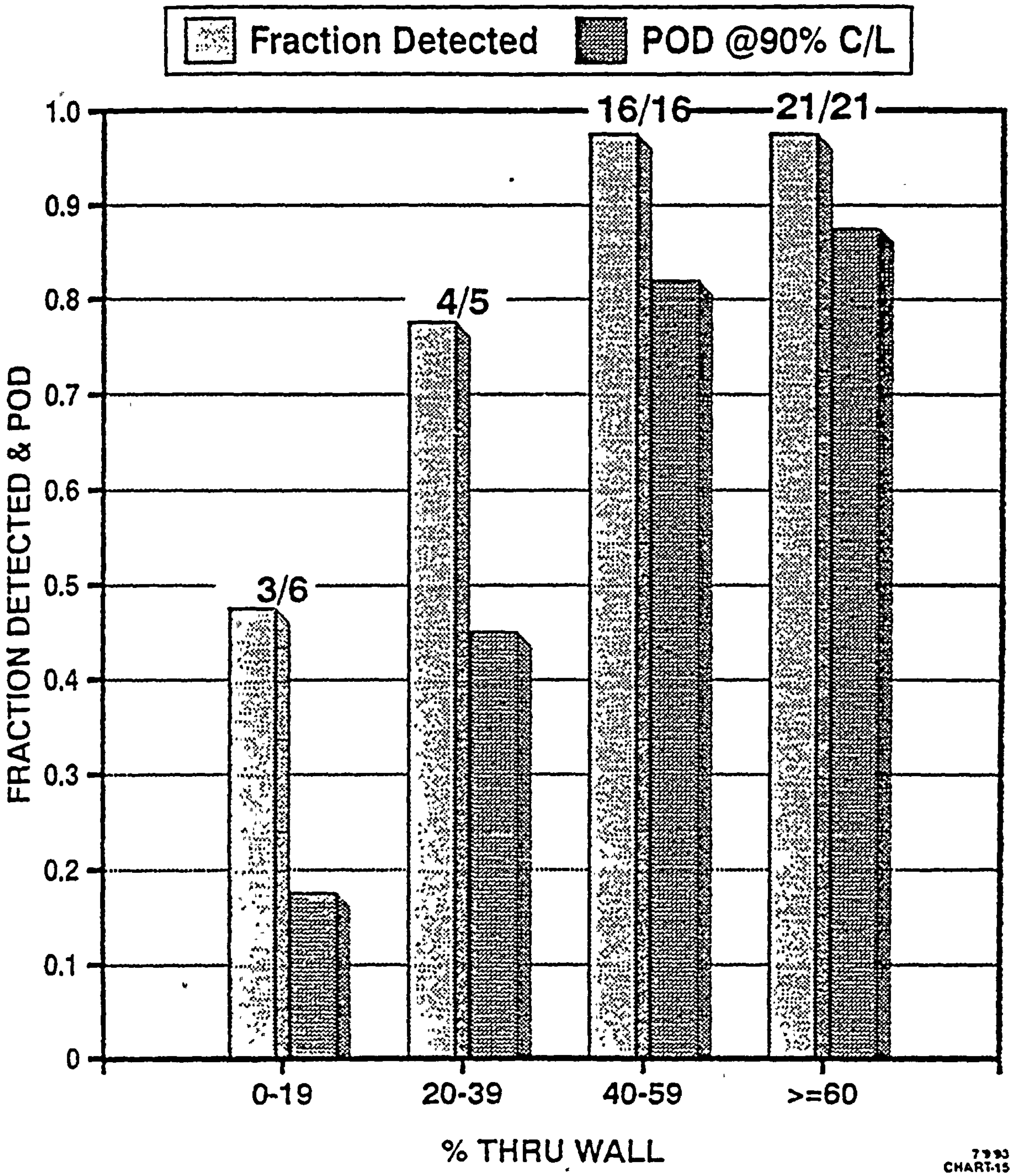
graphic design by Jim Pire

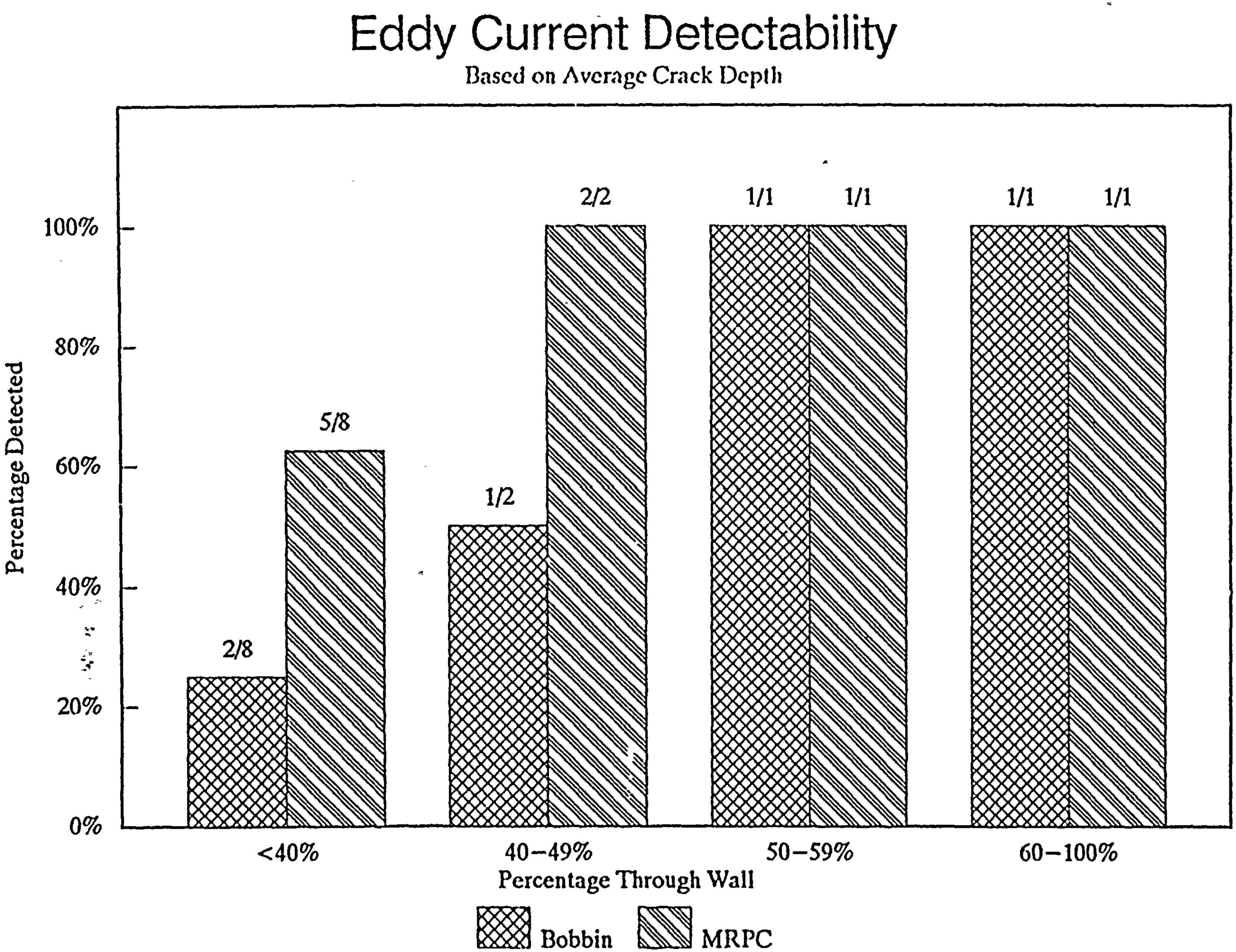
FIGURE V.B.2

FIGURE V.B.2.a

TECHNIQUE QUALIFICATION

ODSCC Prime/QTR Diff Mix-Bobbin
Fraction Detected & POD @90% C/L



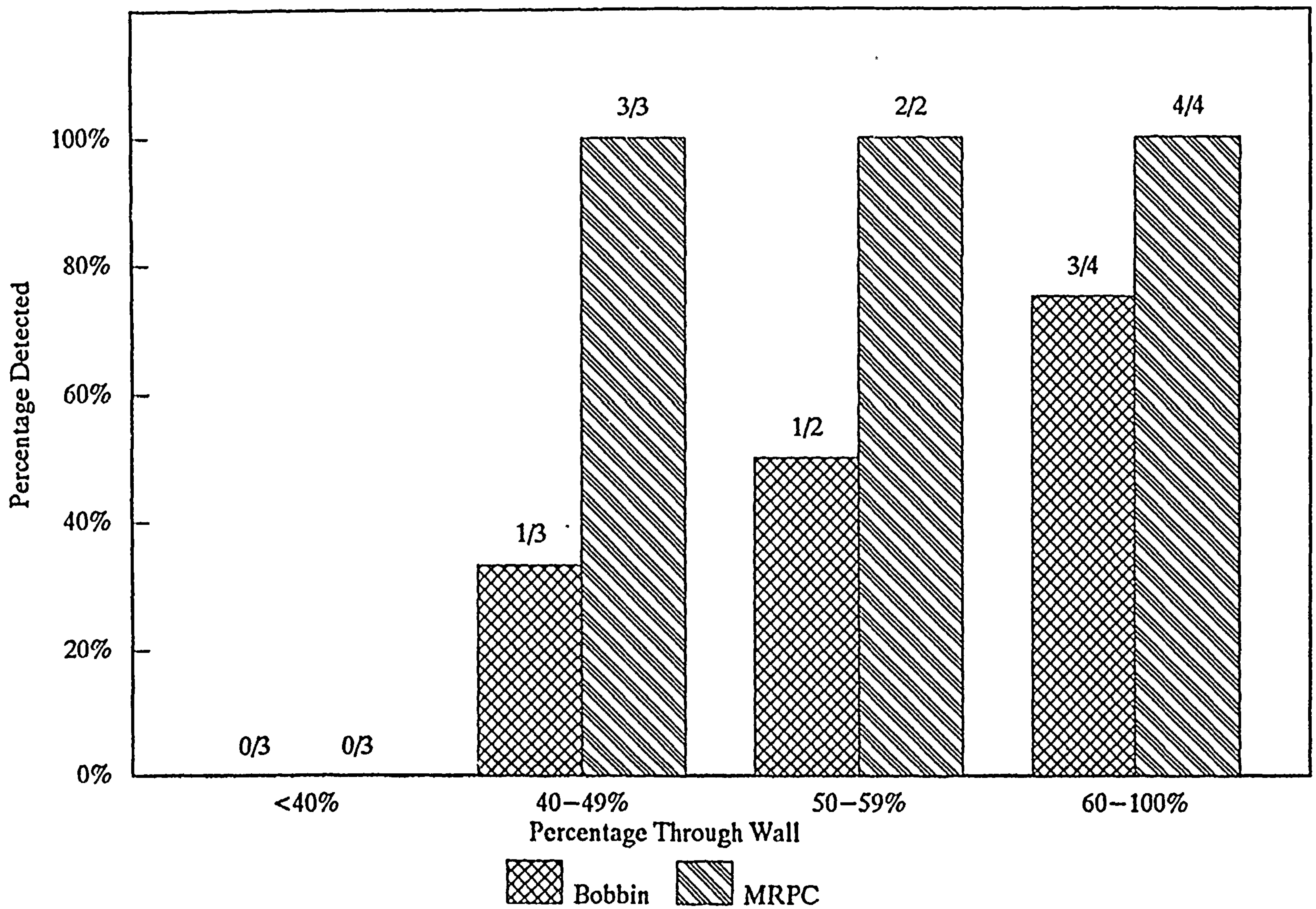


Palo Verde Steam Generator 22

FIGURE V.B.3

Eddy Current Detectability

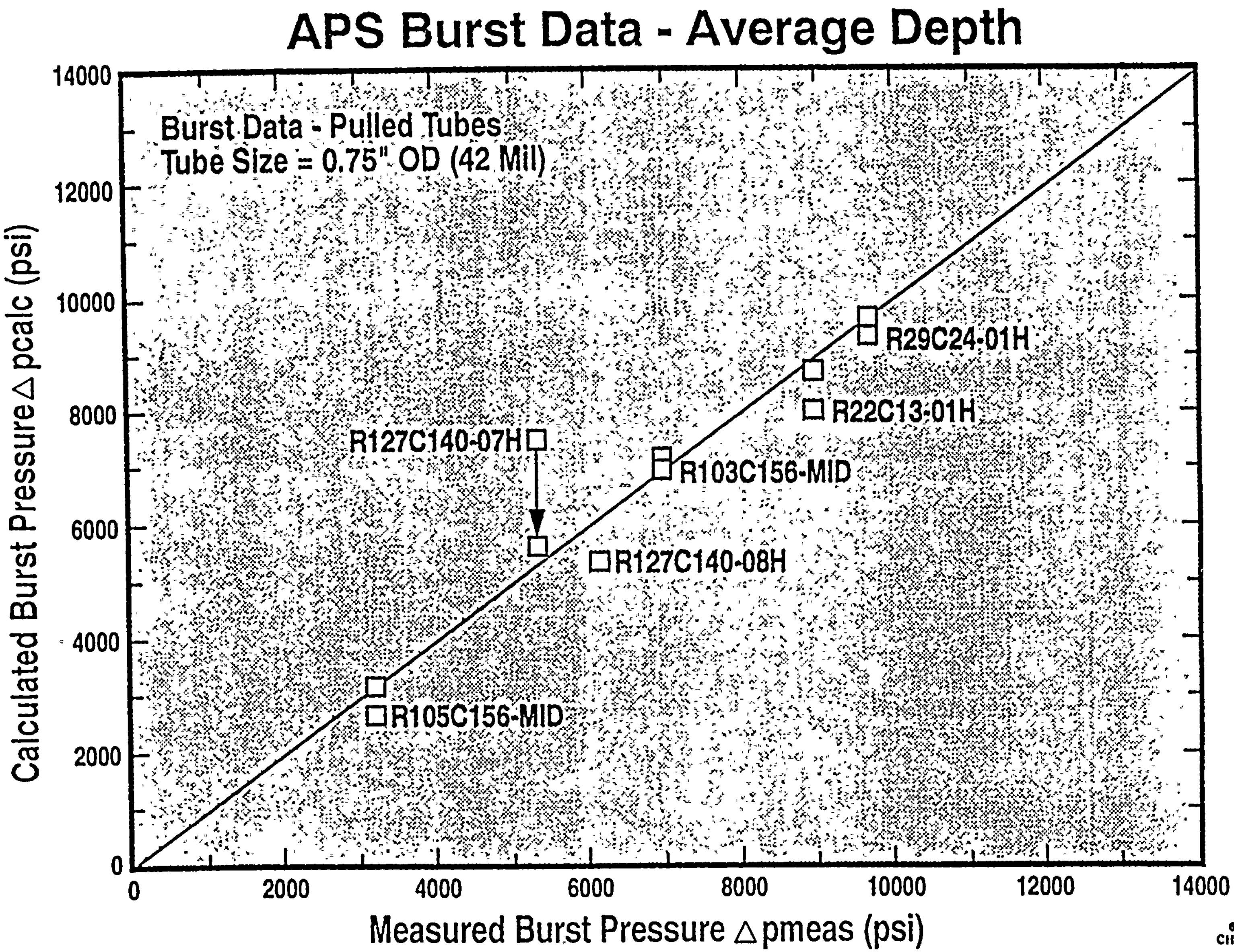
Based on Maximum Crack Depth



Palo Verde Steam Generator 22

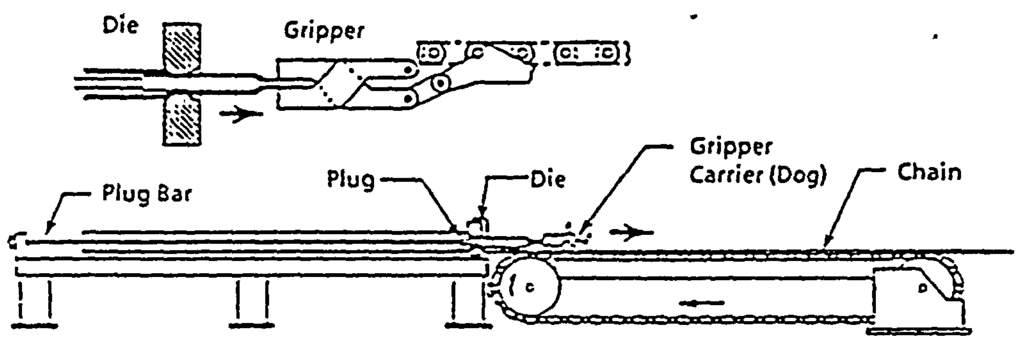
FIG[illegible]V.B.4

FIGURE V.B.5

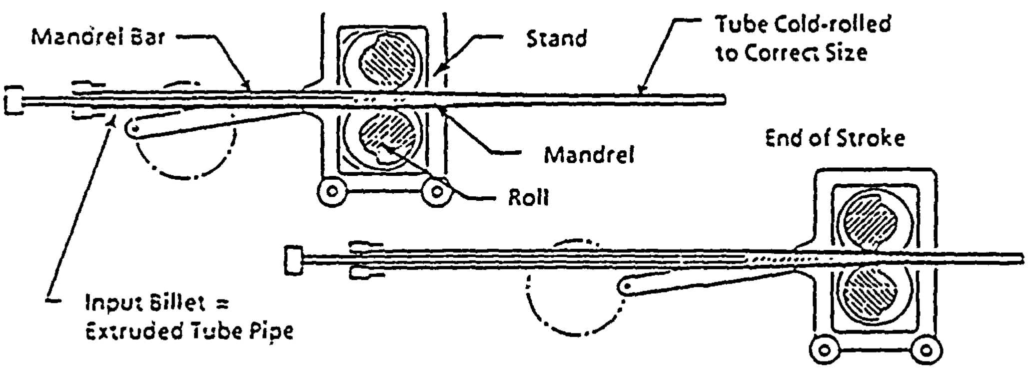


6 29 93
CHART 6

FIGURE V.B.6



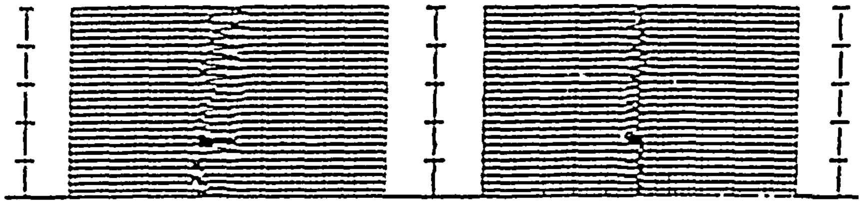
Draw Bench for Cold Drawing Tubes



Pilger Mill

Schematic illustrations of equipment for cold drawing (top) and pilgering (bottom) steam generator tubing.

FIGURE V.B.7



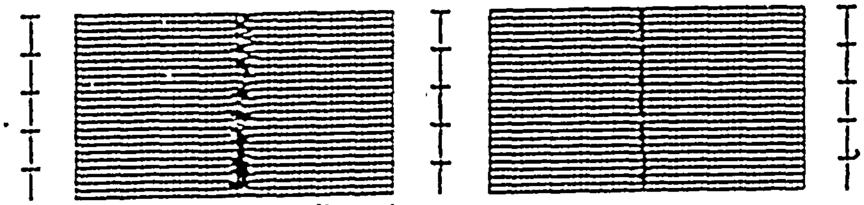
a. Vendor "A"

Vendor A -Pilgered

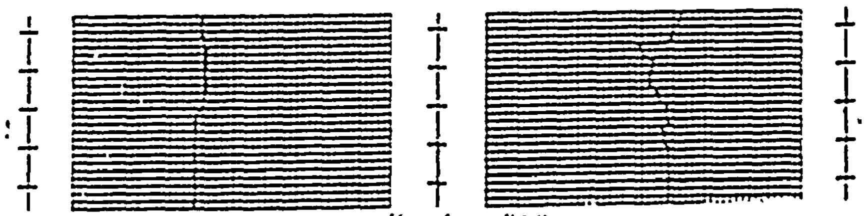
Vendor B -Pilgered

Vendor C -Drawn

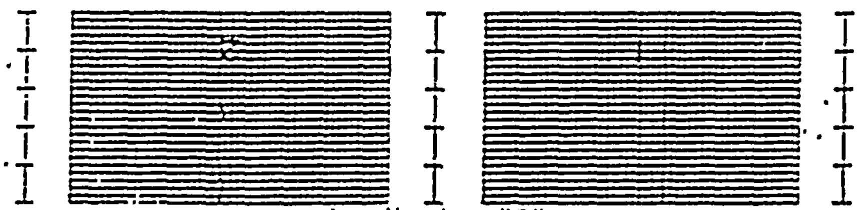
Vendor D -Drawn



b. Vendor "B"



c. Vendor "D"



d. Vendor "C"

ID Eddy Current traces (horizontal on left - 200mv./Div., Verticle on right - 100mv./Div.)

FIGURE V.B.8

PILGERING NOISE HORIZONTAL PRESENTATION

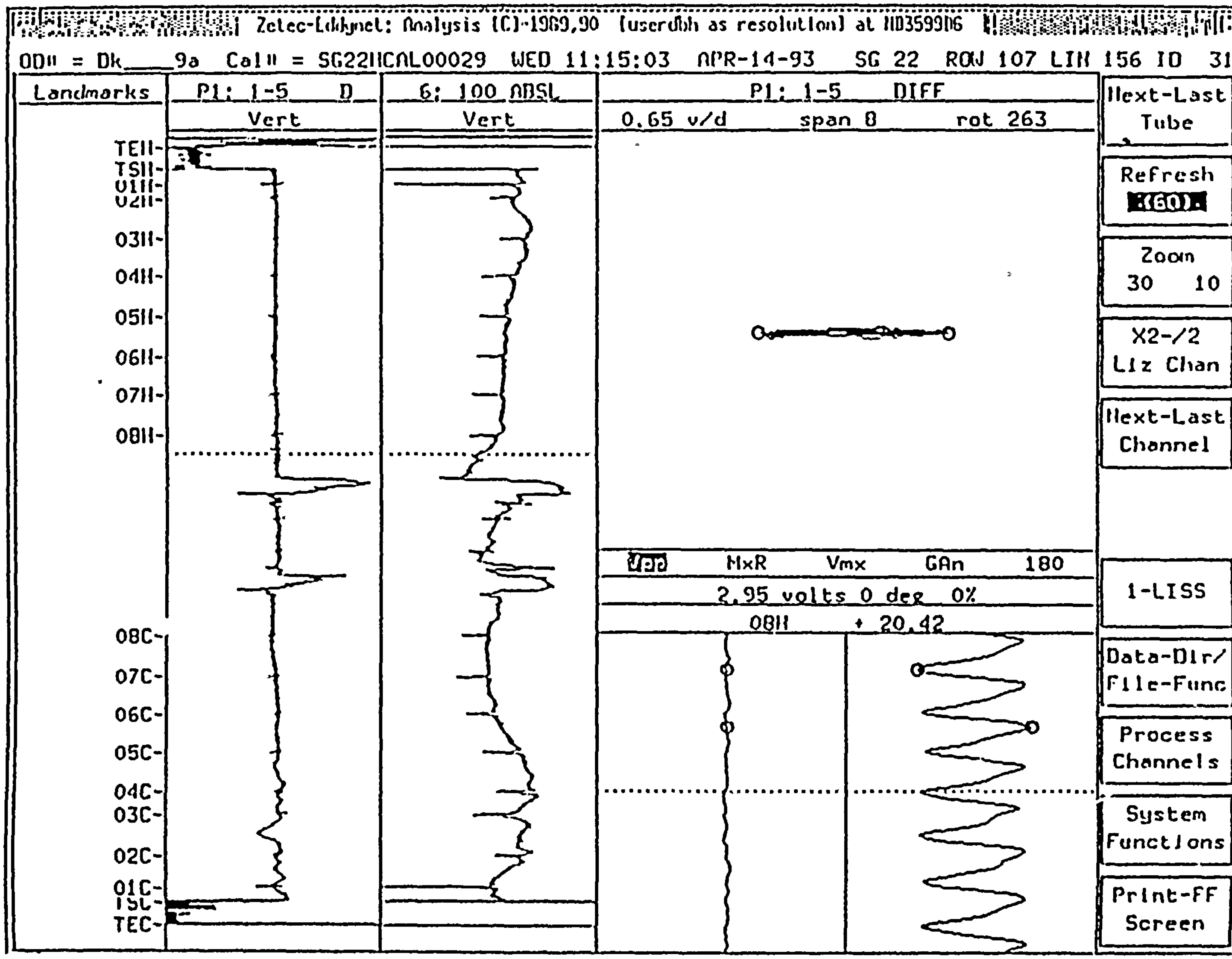


FIGURE V.B.9

100% ASME HOLE CHANNEL P1 USED FOR DEFECT SCREENING

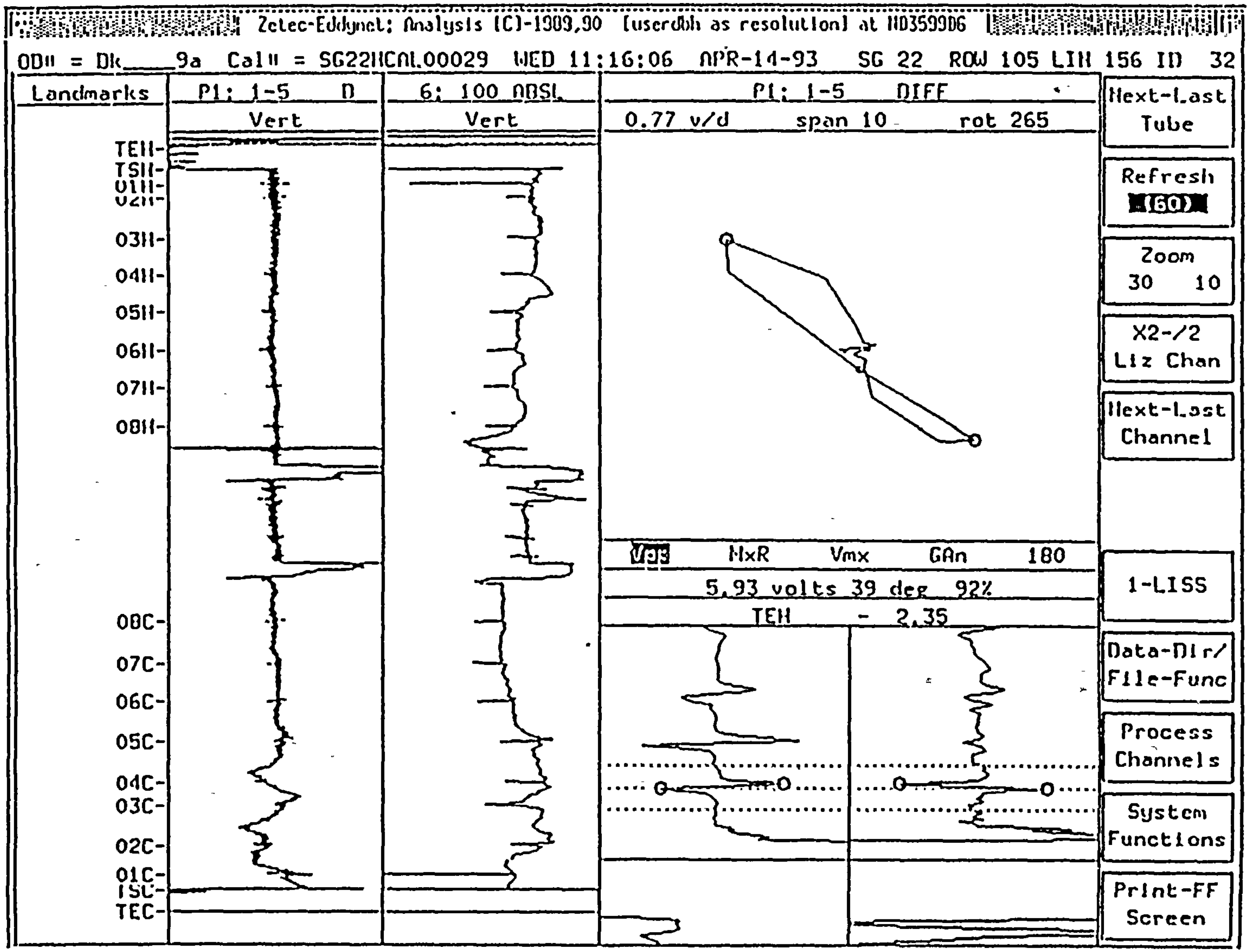


FIGURE V.B.10

TUBE R105C156 HRIZONTAL NOISE IN CHANNEL P1 USED FOR DEFECT SCREENING

LARGE SAI

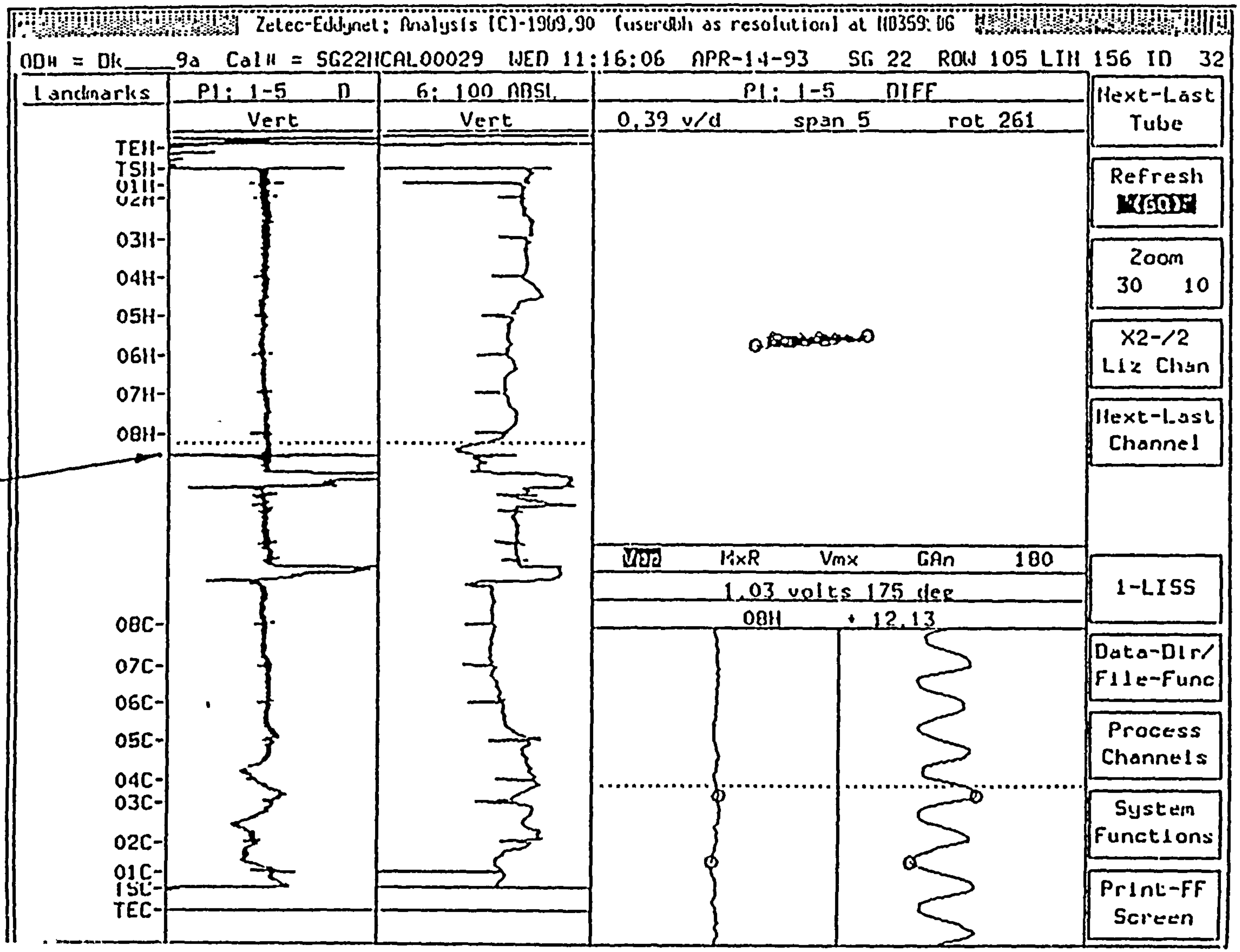


FIGURE V.B.11

TUBE R105C156 SAI DEFECT SIGNAL USING CHANNEL P1

LARGE SAI

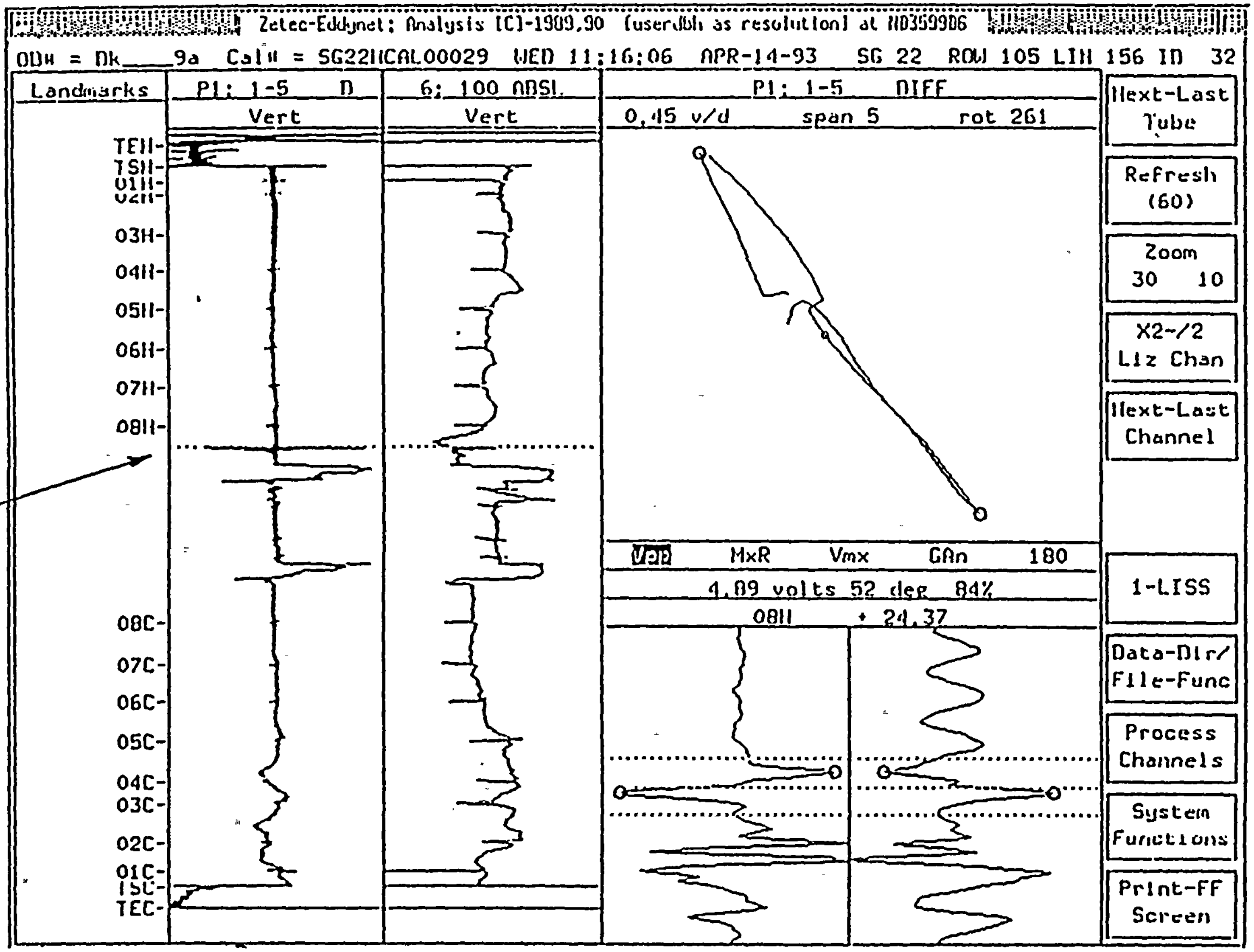


TABLE V.B.1

DEFECT BURST STRENGTH SUMMARY

Tube No.	Defect Location/ Section	Actual Maximum Depth(%)	Actual Average Depth(%)	Field Bob-bin Call	Field MRPC Call	MRPC Length (In)	Burst Length (in)	Burst Pressure (psig)	Calculated Burst (Ave)	Calculated Burst (Max)
R127C140	07H/13	100	40	74	SAI	0.3	0.58	5330	7491	1455
R127C140	08H/15	89.3	58	64	SAI	0.4	1.0	6119	5346	2026
R105C156										
270°	Midspan/16	98	77	85	MAI	1.6	1.38	3200	2656-3171	725-866
90°	"	40	25	NBI	SAI	N/A	N/A	N/A		
0°	"	38	35	NDD	NDD	NDD	N/A	N/A		
0°	"	32	32	NDD	NDD	NDD	N/A	N/A		
0°	"	38	31	NDD	NDD	NDD	N/A	N/A		
R103C156	Midspan//17	57	45	NBI	MAI	.29	0.325	6968	6983-7171	5923-6082
		42	27	NBI	MAI	N/A	N/A	N/A		
R117C40	Midspan/17	61	27	NBI	SAI	N/A	N/A	N/A		
R116C41	Midspan/19	12	N/A	NDD	NDD	NDD	N/A	N/A		

TABLE V.B.1
(continued)

DEFECT BURST STRENGTH SUMMARY

Tube No.	Defect Location/ Section	Actual Maximum Depth(%)	Actual Average Depth(%)	Field Bob-bin Call	Field MRPC Call	MRPC Length (In)	Burst Length (in)	Burst Pressure (psig)	Calculated Burst (Ave)	Calculated Burst (Max)
R22C13	01II/2	56	31	52	SAI	0.25	.325	8948	8011-8688	6412-5913
R29C24	01II/2	40	21	DSI	SAI	0.33	.275	9662	9354-9605	7742-7950

TABLE V.B.2

SIGNAL TO NOISE RATIOS

Sample #	Mill	Process	ASME Standard (volts)	Noise (volts)	S/N Ratio
1	Valinox	Pilgered	6.30	1.11	5.7
2	Valinox	Pilgered	6.06	0.89	6.8
3	Sumitomo	Drawn	6.02	1.11	5.4
4	Sumitomo	Drawn	6.98	1.11	6.3
5	Sandvik	Pilgered	6.70	2.27	3.0
6	Valinox	Pilgered	5.90	3.88	1.5
7	Valinox	Pilgered	6.57	0.40	16.4
8	Valinox	Pilgered	6.56	0.59	11.1
9	Valinox	Pilgered	6.63	0.90	7.4
10	INCO	Drawn	7.68	0.52	13.7
11	INCO	Drawn	7.25	0.53	13.7
12	n/a	n/a	6.11	0.55	11.1
13	n/a	n/a	6.00	0.39	15.4

Reprinted from EPRI NP 6750-SD, April 1990

TABLE V.B.3

SG #	ASME Standard (volts)	Noise (volts)	S/N Ratio
1-1	6	0.84	7.1
1-2	6	0.54	11.1
2-1	6	2.1	2.9
2-2	6	2.1	2.9
3-1	6	0.80	7.5
3-2	6	0.62	9.7

TABLE V.B.4

STEAM GENERATOR 21 S/N RATIO COMPARISON

ROW	LINE	HORIZONTAL NOISE (volts)	VERTICAL NOISE (volts)	NBI SIGNAL (volts)	NQI SIGNAL (volts)	WEAR SIGNAL (volts)	OTHER (volts)	ASME S/N RATIO	DEFECT S/N RATIO
6	1	2.46	.22		.64			2.4	2.9
109	42	1.28	.10	.30				4.68	3
106	45	.35	.10	.36				17.1	3.6
131	46	1.60	.13		.41			3.75	3.1
147	76	1.01	.10	.21				5.9	2.1
149	76	1.00	.13		.41			6.0	3.6
140	89	.84	.10		.46			7.14	4.6
149	98	2.98	.13	.40				2.01	3.1
140	105	1.01	.13				1.27/81%	5.94	9.8
148	111	1.12	.14	.21				5.35	1.5
27	112	..77	.23		1.04			2.17	4.5
146	117	1.14	.13	.29				5.26	2.2
139	118	1.75	.13	.32				3.4	2.5
108	143	3.02	.10			.56/22%		1.98	5.6

Average NBI S/N Ratio = 3.5
Average NQI S/N Ratio = 3.7
Average Vertical Noise = 0.13 volts

TABLE V.B.5

STEAM GENERATOR 22 S/N RATIO COMPARISON

ROW	LINE	HORIZONTAL NOISE (volts)	VERTICAL NOISE (volts)	NBI SIGNAL (volts)	NQI SIGNAL (volts)	WEAR SIGNAL (volts)	OTHER SIGNAL (volts)	ASME S/N RATIO	DEFECT S/N RATIO
22	13	1.37	.15				52% 1.29		8.6
10	23	1.46	.15				30% .64		4.3
29	24	.91	.16				DSI .41		2.6
97	38	1.41	.05	.08				4.25	1.6
112	39	2.58	.11		.65				14.6
115	40	.69	.09		.29				3.2
117	40	2.02	.15	.36				2.97	2.4
115	42	.75	.12		.17				1.4
117	42	1.5	.08				49% 1.23		15.38
123	44	1.55	.08			32% 1.21			15.1
118	45	1.07	.09			19% .39			4.3
123	46	1.58	.09			12% .55			6.1
128	47	1.83	.35				82% 6.37		18.2
129	48	1.49	.10			18% .72			7.2
128	49	1.53	.10			39% 3.11			31.1
123	50	1.94	.09			27% 1.97			21.89

TABLE V.B.5
(continued)

STEAM GENERATOR 22 S/N RATIO COMPARISON

ROW	LINE	HORIZONTAL NOISE (volts)	VERTICAL NOISE (volts)	NBI SIGNAL (volts)	NQI SIGNAL (volts)	WEAR SIGNAL (volts)	OTHER SIGNAL (volts)	ASME S/N RATIO	DEFECT S/N RATIO
129	50	1.45	.12			8% .56			4.7
141	74	1.91	.05	.10				3.14	2.0
151	90	1.70	.12				73% .52		4.3
131	92	3.09	.10	.14				1.94	1.4
41	94	1.28	.14			99% 4.24			30.3
127	96	1.74	.17	.19				3.44	1.1
129	96	2.00	.41			19% 1.91			4.7
133	104	2.00	.11	.52				3.0	4.7
134	105	2.33	.15	.64				2.58	4.3
134	111	3.14	.08		.59				7.4
149	114	1.00	.07	.28				6.0	4.0
144	115	1.64	.21		.24				1.1
146	115	1.17	.15		.39				2.6
150	115	1.33	.13		.95				7.3
137	116	1.78	.18		.42				2.3
134	117	3.58	.14	.28				1.67	2.0
145	118	2.10	.11		.63				5.7

TABLE V.B.5
(continued)

STEAM GENERATOR 22 S/N RATIO COMPARISON

ROW	LINE	HORIZONTAL NOISE (volts)	VERTICAL NOISE (volts)	NBI SIGNAL (volts)	NQI SIGNAL (volts)	WEAR SIGNAL (volts)	OTHER SIGNAL (volts)	ASME S/N RATIO	DEFECT S/N RATIO
140	119	2.26	.19				58% .68		3.6
142	119	1.34	.35		.44				1.3
142	123	1.06	.10	.33				5.66	3.3
137	124	2.40	.34			28% .75			2.2
141	124	1.80	.10	.33				3.33	3.3
135	130	.97	.10	.12				6.19	1.2
129	132	2.36	.10				67% 1.49		14.9
135	132	1.98	.12	.25				3.03	2.1
128	133	1.67	.10				88% 2.97		29.7
128	135	1.70	.09			31% 3.87			43
125	136	2.01	.09				57% 2.26		25
131	136	3.33	.17	.58				1.80	3.4
126	137	1.45	.15	.15				4.13	1.0
128	137	1.70	.15				55% 2.17		14.5
123	138	1.83	.12	.50				3.27	4.2
125	138	1.55	.10			28% 1.36			13.6
129	138	2.01	.18	.24				2.98	1.3
128	139	2.23	.10	.30				2.69	3.0

TABLE V.B.5
(continued)

STEAM GENERATOR 22 S/N RATIO COMPARISON

ROW	LINE	HORIZONTAL NOISE (volts)	VERTICAL NOISE (volts)	NBI SIGNAL (volts)	NQI SIGNAL (volts)	WEAR SIGNAL (volts)	OTHER SIGNAL (volts)	ASME S/N RATIO	DEFECT S/N RATIO
127	140	1.82	.15			39% 1.32			8.8
122	141	2.69	.18		.27				1.5
128	141	1.60	.11			37% 1.34			12.2
74	143	2.75	.10			23% .89			8.9
115	144	1.89	.13	.33				3.17	2.5
117	144						BURST		NA
118	145	.94	.13			9% .36			2.7
124	145	1.57	.14			37% 3.13			22.4
122	147	2.17	.09	.26				2.76	2.9
110	149	1.90	.09				85% .45		5.0
17	152	1.02	.14				DSI .81		5.8
110	153	1.03	.13				DSI .44		3.4
103	156	.79	.12	.15				7.59	1.3
105	156	1.26	.09				84% 3.85		43
107	156	2.76	.15		.34				2.7
104	157	.88	.12				85% .51		4.3

TABLE V.B.5
(continued)

STEAM GENERATOR 22 S/N RATIO COMPARISON

ROW	LINE	HORIZONTAL NOISE (volts)	VERTICAL NOISE (volts)	NBI SIGNAL (volts)	NQI SIGNAL (volts)	WEAR SIGNAL (volts)	OTHER SIGNAL (volts)	ASME S/N RATIO	DEFECT S/N RATIO
97	158	1.50	.07	.19				4.0	2.7
93	160	1.83	.14	.28				3.28	2.0

Average NBI S/N Ratio = 2.5:1
Average NQI S/N Ratio = 4.2:1
Average Vertical Noise = 0.13

FIGURE V.C.1

Tube Pull Candidates

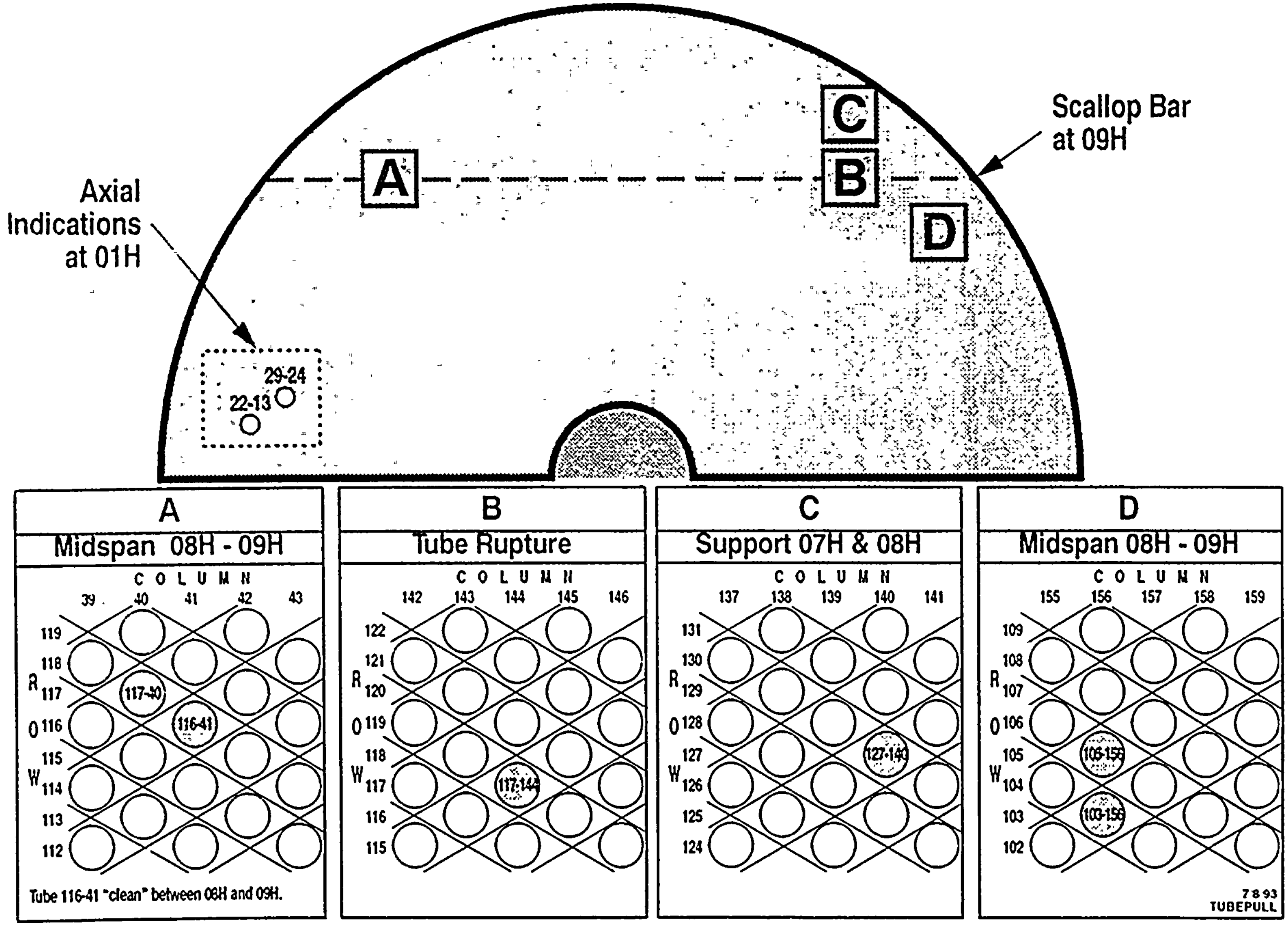
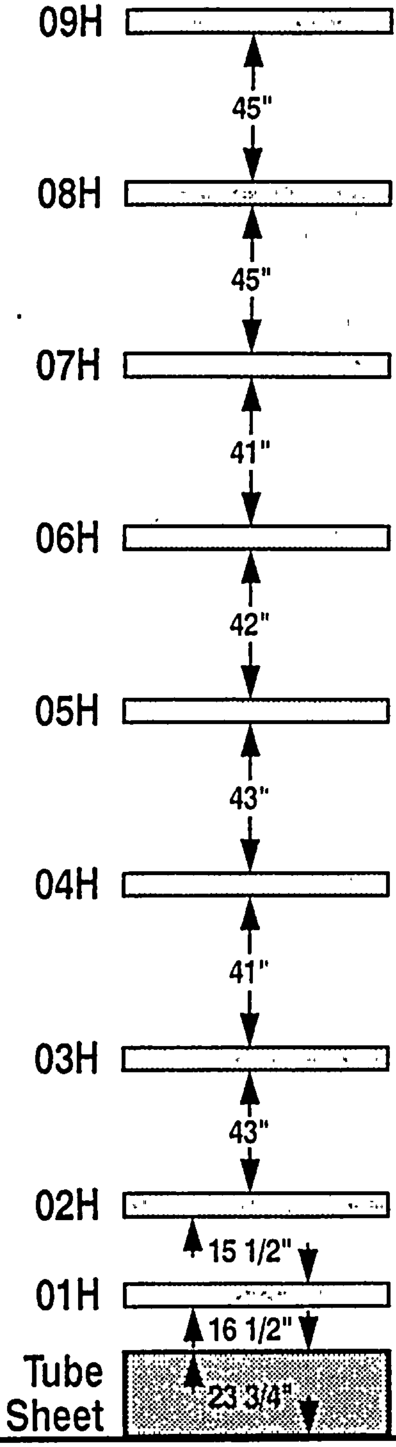


FIGURE V.C.2

Steam Generator 22 Tube 103-156 Section Index (CE)



Whip cut at 347 1/4" from primary face

17	25 3/4"
16	22 "
15	17 5/8"
14	24 1/2"
13	14 7/8"
12	27 7/8"
11	15 1/4"
10	26 7/8"
9	15 1/2"
8	26 1/4"
7	15 7/8"
6	21 5/8"
5	3 3/16"
4	17 1/4"
3	25"
2	17 3/8"
1	27 15/16"

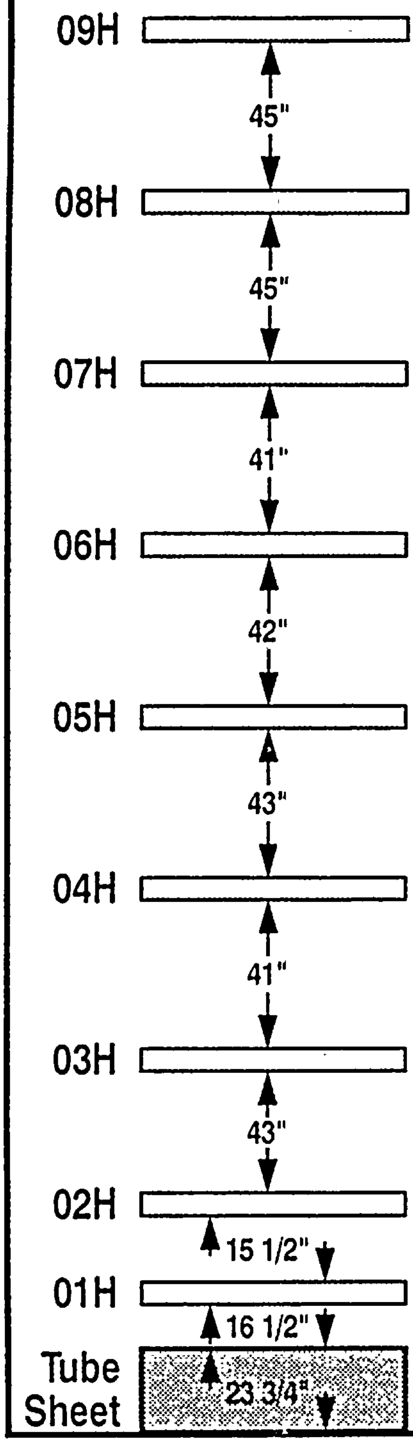
6 21 93
103-156

General Notes:

1) Mechanical scribe faces towards tube 104-155
2) 01H support is a 1" thick baffle plate. All other supports are 2" thick eggcrates.
3) 09H support shown for reference only - tube does not go thru 09H.

FIGURE V.C.3

Steam Generator 22 Tube 105-156 Section Index (CE)



Whip cut at 347 7/8" from primary face

16	25 1/2"
15	21 3/4"
14	20 13/16"
13	24 5/16"
12	13 5/8"
11	25"
10	17 1/4"
9	26 3/4"
8	15 11/16"
7	26 1/2"
6	13 15/16
5	25 1/2"
4	14 3/4"
3	26"
2	25 3/4"
1	22 1/2"

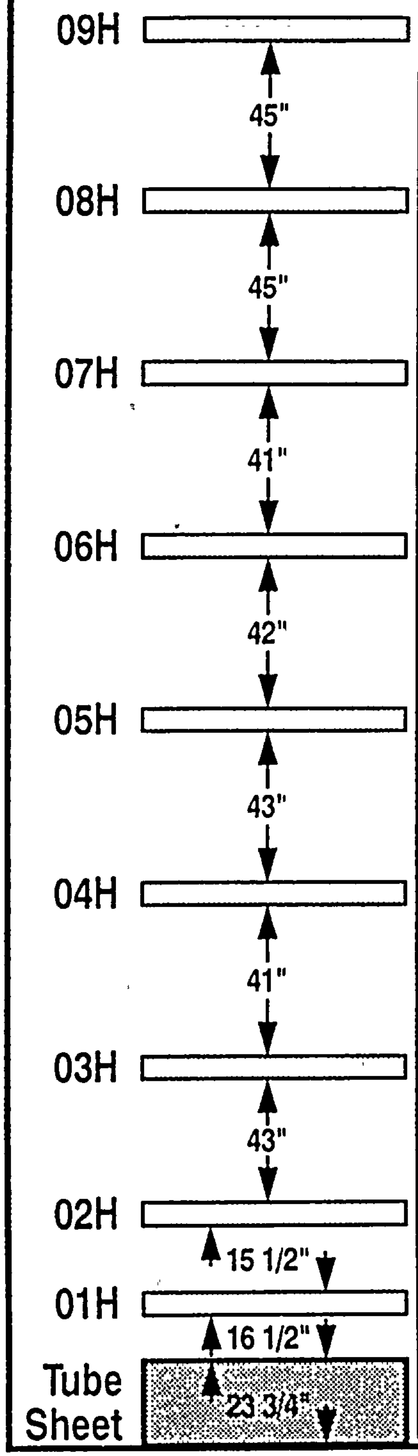
6 21 93
105-156

General Notes:

1) Mechanical scribe faces towards tube 106-155
2) 01H support is a 1" thick baffle plate. All other supports are 2" thick eggcrates.
3) 09H support shown for reference only - tube does not go thru 09H.

FIGURE V.C.4

Steam Generator 22 Tube 117-144 Section Index (CE)



Whip cut at 345 1/4" from primary face

16	24 1/4"
15	22 1/8"
14	22 1/8"
13	23 7/8"
12	17 15/16"
11	24 1/2"
10	17"
9	21 3/16"
8	22 1/4"
7	24 3/4"
6	17 3/8"
5	20 3/8"
4	20 3/8"
3	20 1/4"
2	17 1/2"
1	28 3/4"

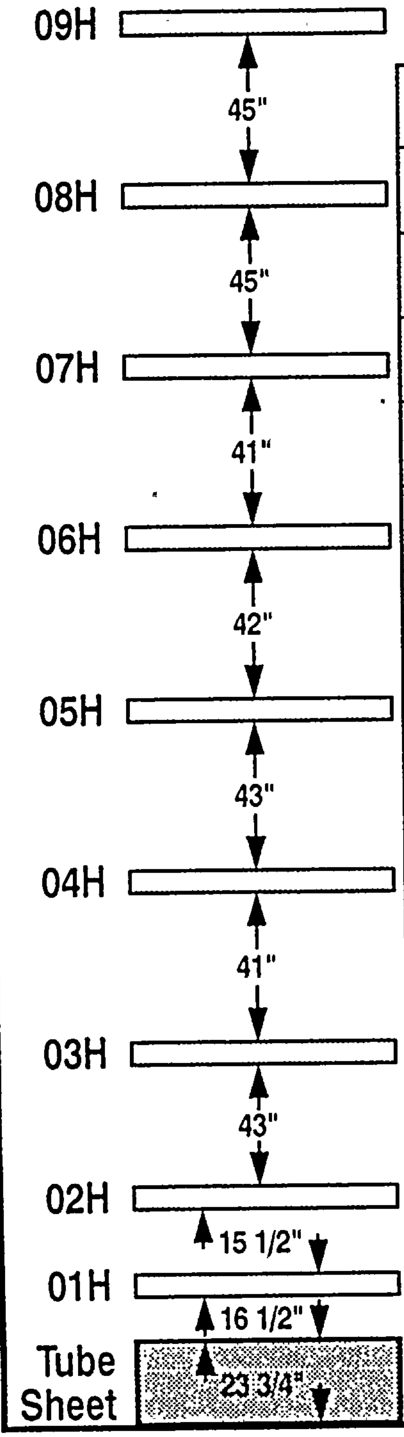
6 21 93
117-144

General Notes:

1) Mechanical scribe faces towards tube 118-143
2) 01H support is a 1" thick baffle plate. All other supports are 2" thick eggcrates.
3) 09H support shown for reference only - tube does not go thru 09H.

FIGURE V.C.5

Steam Generator 22 Tube 127-140 Section Index (CE)



Whip cut at 345 1/4' from primary face

16	27 5/8"
15	24 5/8"
14	19 1/8"
13	25 1/4"
12	19 1/4"
11	22 1/4"
10	20 1/8"
9	21 1/8"
8	22 1/2"
7	21"
6	18 15/16"
5	19"
4	20 1/16"
3	23 9/16"
2	17"
1	28 5/8"

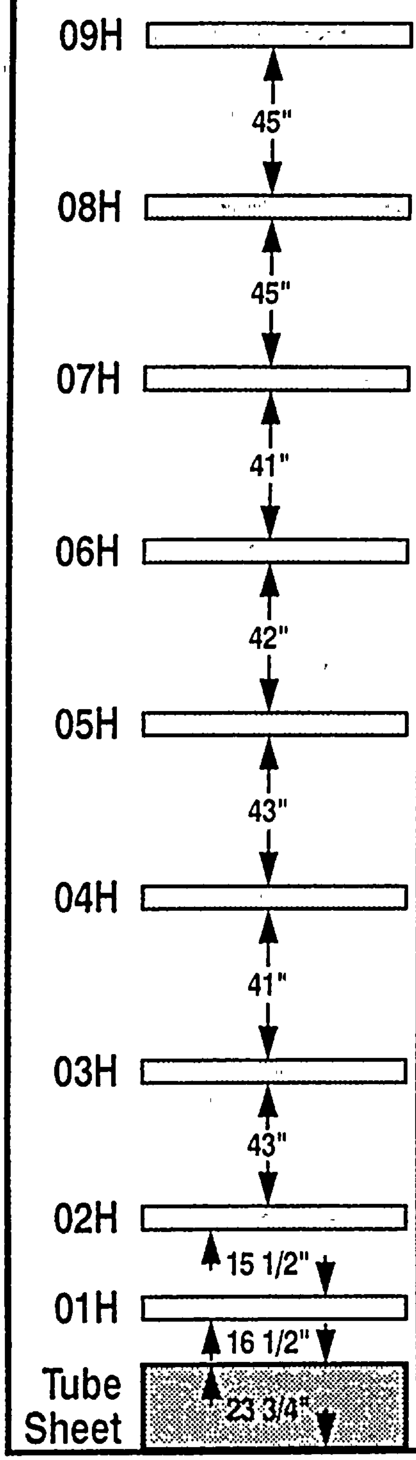
6 21 93
127-140

General Notes:

1) Mechanical scribe faces towards tube 118-143
2) 01H support is a 1" thick baffle plate. All other supports are 2" thick eggcrates.
3) 09H support shown for reference only - tube does not go thru 09H.

FIGURE V.C.6

Steam Generator 22 Tube 117-40 Section Index (B&W)



17	13 1/8"
16	22 1/2"
15	23"
14	21 1/2"
13	21"
12	20 1/2"
11	19 3/8"
10	19 1/2"
9	21 7/8"
8	18 1/2"
7	22 3/8"
6	18"
5	24 1/2"
4	16 1/4"
3	24"
2	20"
1	28 3/4"

Whip cut at 359 1/2" from primary face (below batwing)

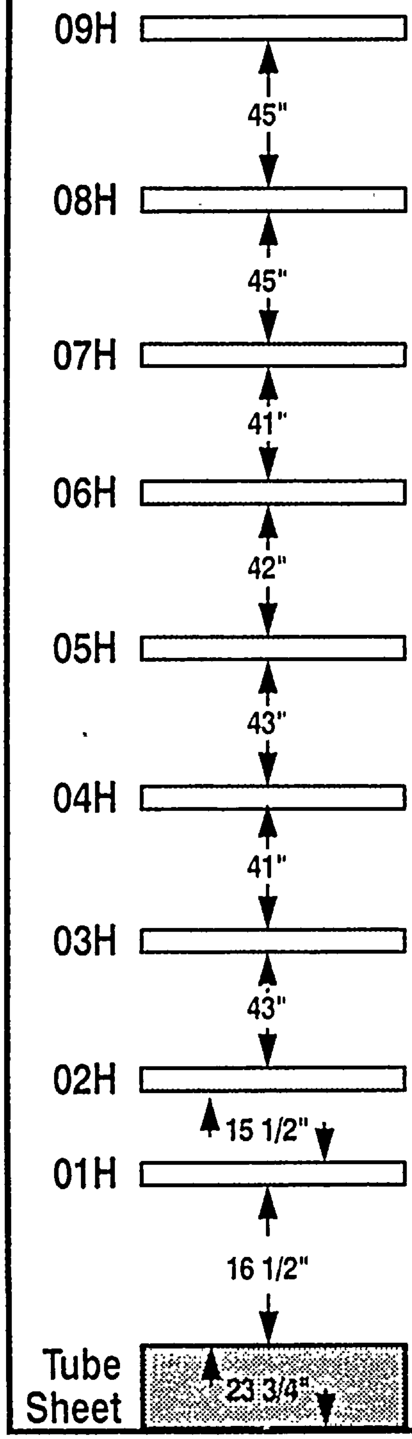
6 21 93
117-40

General Notes:

1) Mechanical scribe faces towards tube 115-40
2) 01H support is a 1" thick baffle plate. All other supports are 2" thick eggcrates.
3) 09H support shown for reference only - tube does not go thru 09H.

FIGURE V.C.7

Steam Generator 22 Tube 116-41 Section Index (B&W)



Whip cut at 358.35" from primary face

19	19 1/2"
18	14 5/16"
17	23 3/16"
16	21 11/16"
15	22 1/4"
14	18 3/4"
13	23 3/8"
12	17 3/8"
11	23 3/4"
10	22 3/8"
9	24 3/4"
8	13 1/2"
7	24 7/8"
6	22 5/8"
5	16 1/8"
4	12 3/4"
3	5 1/8"
2	13 3/16"
1	15 1/2"

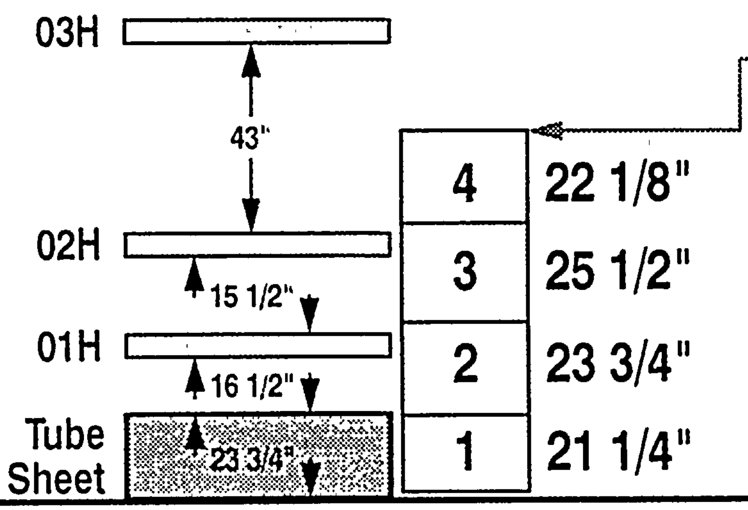
5 21 93
116-41

General Notes:

1) Mechanical scribe faces towards tube 114-41
2) 01H support is a 1" thick baffle plate. All other supports are 2" thick eggcrates.
3) 09H support shown for reference only - tube does not go thru 09H.

FIGURE V.C.8

Steam Generator 22 Tube 29-24 Section Index (B&W)



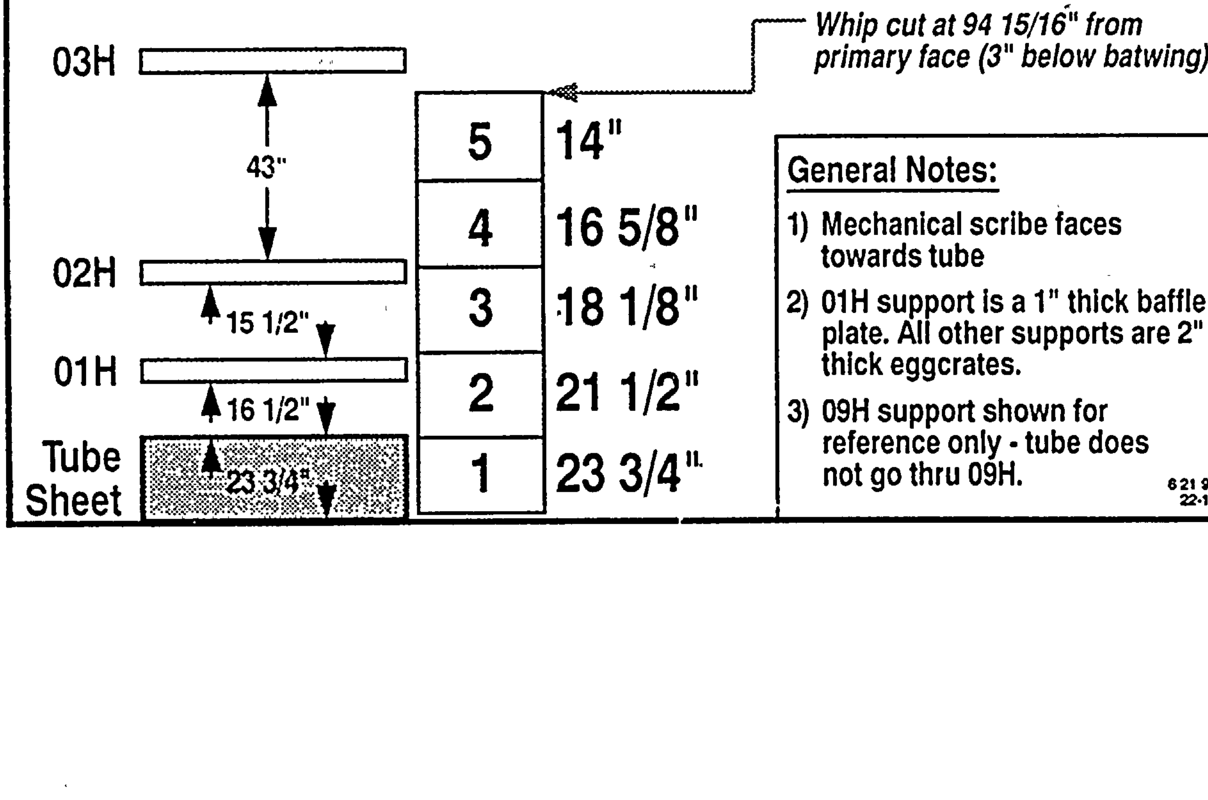
General Notes:

1) Mechanical scribe faces towards tube
2) 01H support is a 1" thick baffle plate. All other supports are 2" thick eggcrates.
3) 09H support shown for reference only - tube does not go thru 09H.

6 21 93
29-24

FIGURE V.C.9

Steam Generator 22 Tube 22-13 Section Index (B&W)



General Notes:

1) Mechanical scribe faces towards tube
2) 01H support is a 1" thick baffle plate. All other supports are 2" thick eggcrates.
3) 09H support shown for reference only - tube does not go thru 09H.

6 21 93
22-13

Table V.C.1

PALO VERDE UNIT 2
PRIMARY/SECONDARY TUBE PULL CANDIDATES
SG 22

ROW	COL	ELEV	%TW	RUPTURED TUBE	MID SPAN	CRACKS@ SUPPORT-BW 09H, 08H & 07H	CRACKS/I NC @ 01H	TUBE RPC - YES/BOBBIN NO.	DEGRADED TUBE FOR BURST TES LAB	ECT DETECTABI LITY	MULTI @ MIDSPAN	DEPOSIT
01H												
22	13	1H	52%				X		X	X		
29	24	1H	DSI				X		X	X		
SECOND PRIORITY												
10	23	1H	30%				X		X	X		
MID SPAN												
117	144	8H + 40"	100%	X	X					X	X	X
103	156	8H + 25"	SAI		X			X	X	X		
105	156	8H + 26"	>80%		X				X	X		X
117	40	8H + 40"	SAI		X			X	X	X		
SECOND PRIORITY												
117	42	8H + 40"	46%		X				X	X		X
104	157	8H + 26"	>80%		X				X	X		X
@ SUPPORT												
127	140	7H 8H	31% 39%			X			X	X		
SECOND PRIORITY												
128	137	8H	44%			X			X	X		

Table V.C.1

PALO VERDE UNIT 2
PRIMARY/SECONDARY TUBE PULL CANDIDATES
SG 22

ROW	COL	ELEV	%TW	RUPTURED TUBE	MID SPAN	CRACKS@ SUPPORT-BW 09H, 08H & 07H	CRACKS/I NC. @ 01H	TUBE RPC - YES/BOBBIN NO.	DEGRADED TUBE FOR BURST TES LAB	ECT DETECTABI LITY	MULTI @ MIDSPAN	DEPOSIT
125	138	8H	28%			X			X	X		
110	149	8H	39%			X			X	X		
"CLEAN TUBE"												
116	41	N/A	N/A							X		
SECOND PRIORITY												
116	143	N/A	N/A							X		
116	145	N/A	N/A							X		

Table V.C.2

PALO VERDE UNIT 2
TUBE PULL CANDIDATES

TUBE

ROW	COL	CUT ELEVATION	LAB WHICH PERFORMED EXAMINATION
22	23	Below 03H	BWNT
29	24	Below 03H	BWNT
117	144	Below Rupture (10 1/2" Below 09H)	CE
105	156	Below BW1	CE
103	156	Below BW1	CE
116	41	Below BW1	BWNT
127	140	Below 09H	CE
117	40	Below BW1	BWNT

Table V.D.1

PALO VERDE UNIT 2
(TUBE PULL VIDEO CHECKLIST)
SG 22

PULL SEQUENCE	TUBE ROW	COL	CUT ELEVATION	LAB*	AREAS OF INTEREST VIDEO EXAMINATIONS		
1	22	13	Below 3H	BWNT	1) Top of tube sheet 2) Look at 1H**		
2	29	24	Below 3H	BWNT	1) Top of tube sheet 2) Look at 1H**		
5	117	144	Below Rupture 10 1/2" Below 09H	CE	1) Detailed look at tube near cut 2) Detailed look at 8H + 30" 3) Detailed look at 8H		
6	105	156	Below BW1	CE	1) Deposits and flaws on	107, 104, 103,	156, 157, 156
					2) Detailed look at 08H, 07H		
					3) Pull first to look at before it is cut	103,	156
					4) Look at 1H**		
7	103	156	Below BW1	CE	1) Deposits and flaws on	107, 104,	156, 157
					2) Detailed look at 08H, 07H		

* LAB which performed examination
** 1H can be looked at during any of the pulls.

Table V.D.1

PALO VERDE UNIT 2
(TUBE PULL VIDEO CHECKLIST)
SG 22

PULL SEQUENCE	TUBE ROW	COL	CUT ELEVATION	LAB*	AREAS OF INTEREST VIDEO EXAMINATIONS
3	116	41	Below BW1	BWNT	1) Detailed view of 9H, scallops, 117-40, 117-42 2) Detailed view of 8H + 40" for flaws on 117-42 and 117-40 3) General look at 08H, 07H 4) 9H-2" look at 118-41 (20%)
8	127	140	Below 9H	CE	1) Detailed look at 08H support 2) Look for flaw on 128-141 near 08H
4	117	40	Below BW1	BWNT	1) Look at 08H + 40" 2) Look at 08H 3) Look at 07H

* LAB which performed examination

Table V.E.1

PALO VERDE UNIT 2
SG 22 ORIENTATION TEST

ROW	COL.	ELEV.	T Pull*	Axial Flaw	Deposit	Wear	MRPC Not Bobbin
103	156	8H+20	P	X	X(2)	X	X
		8H				X	
104	157	8H+25	S	X	X		
105	156	8H+25	P	X	X(2)		
		8H				X	
107	152	BW1		X			
107	156	8H+25		X	X		
110	149	8H	S	X			
		BW1		X			
115	40	8H+40		X	X		
115	42	8H+40		X	X		
115	144	8H+35		X	X		
116	41	9H	P			X	
116	143	9H	S			X	
116	145	9H	S			X	
117	40	8H+40	P	X		X	X
		9H					
117	42	8H+40	S	X	X		
		9H				X	
117	144	8H+40	P	X	X		
118	145	9H		X			
121	142	9H		X			
123	50	9H		X			

*Tube Pull - (P) Primary tube pull candidates.
(S) Secondary tube pull candidates.

NOTE: Tubes 22-13 and 29-24 were pulled but indications at the 01H were not tested for orientation

Table V.E.1

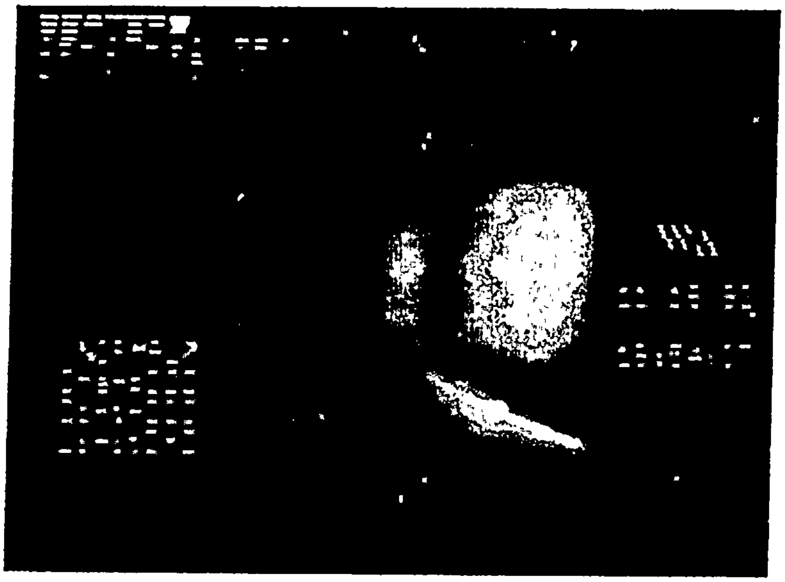
PALO VERDE UNIT 2
SG 22 ORIENTATION TEST

ROW	COL	ELEV	T Pull*	Axial Flaw	Deposit	Wear	MRPC Not Bobbin
124	145	BW1		X			
125	136	9H		X			
125	138	8H	S	X			
127	140	8H	P	X			
		7H		X			
128	133	9H		X			
128	135	9H		X			
128	137	8H	S	X			
128	141	8H		X			
129	132	9H		X			
140	119	9H+22		X	X		
142	119	9H+22		X	X		
150	125	9H+25			X		
150	127	9H+25			X		

*Tube Pull - (P) Primary tube pull candidates.
(S) Secondary tube pull candidates.

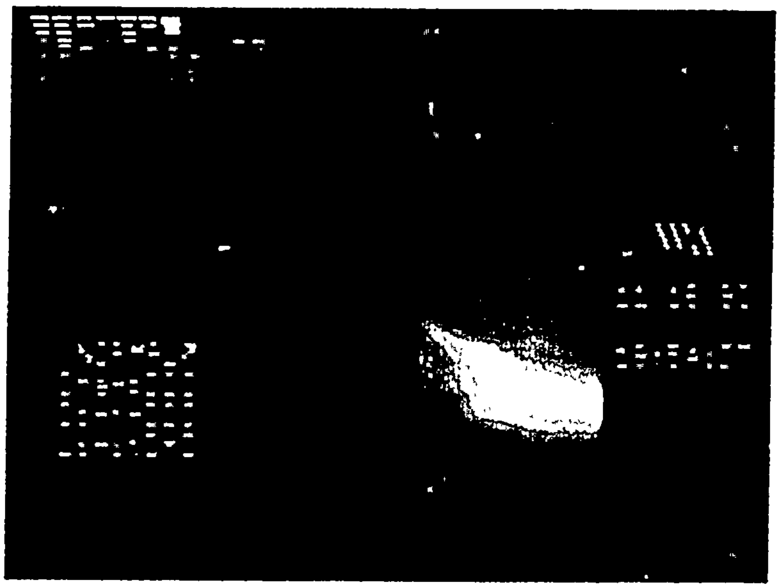
NOTE: Tubes 22-13 and 29-24 were pulled but indications at the 01H were not tested for orientation

FIGURE V.D
PICTURE 1



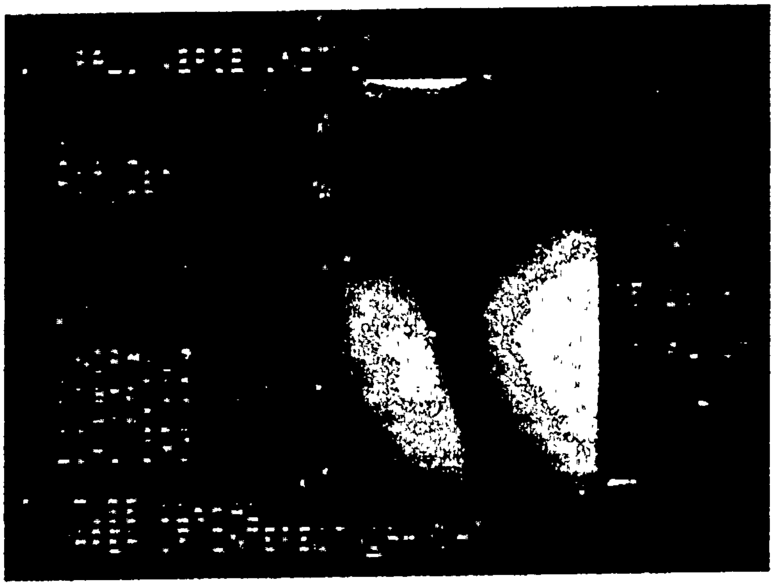
BRIDGED TUBE GAP ABOVE 08H
(TUBES 117-40 AND 115-40)

FIGURE V.D
PICTURE 2



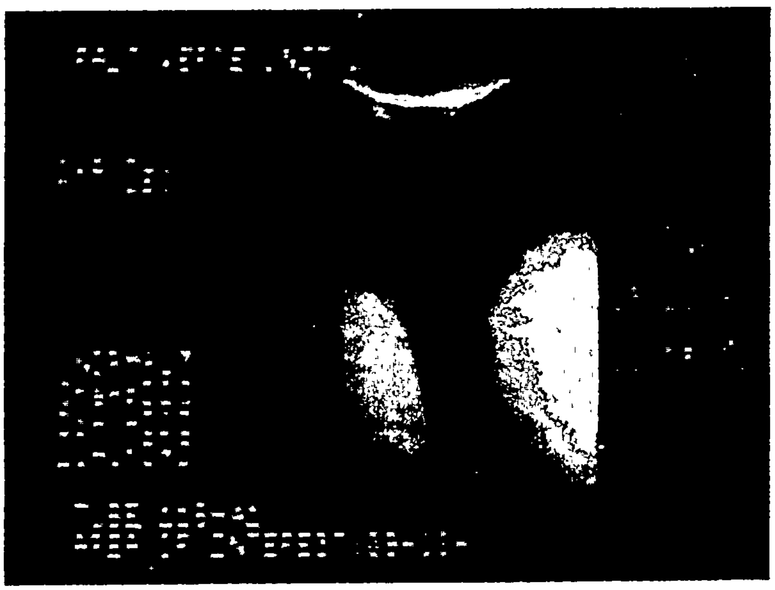
LESS THAN NOMINAL TUBE GAP
ABOVE 08H BUT BELOW AREA SHOWN
ON PICTURE 1
(TUBES 117-40 AND 115-40)

FIGURE V.D
PICTURE 3



BRIDGED TUBE GAP ABOVE 08H
(TUBES 117-42 AND 115-42)

FIGURE V.D
PICTURE 4

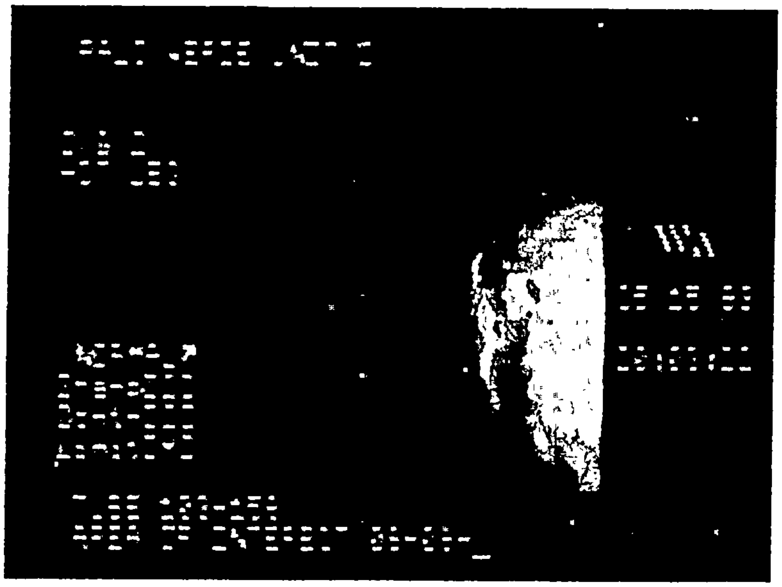


LESS THAN NOMINAL TUBE GAP
ABOVE 08H BUT BELOW AREA SHOWN
ON PICTURE 3
(TUBES 117-42 AND 115-42)

FIGURE V.D
PICTURE 5

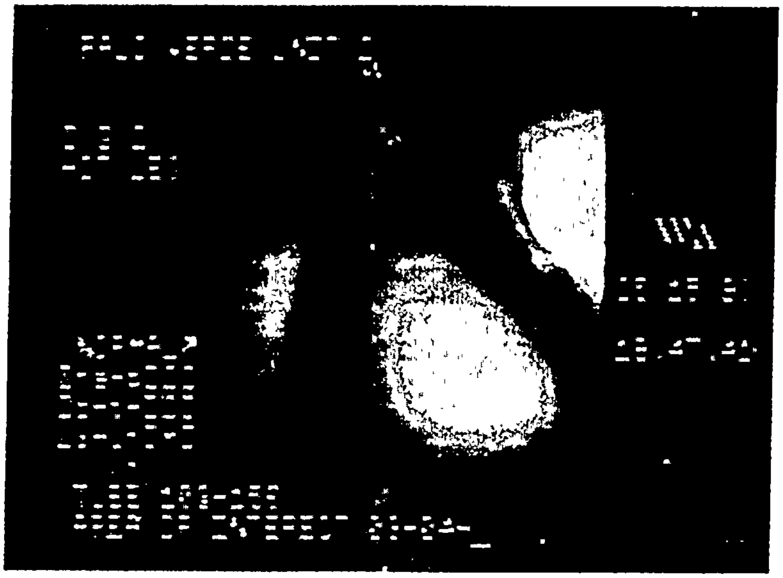
RIDGE DEPOSIT ON TUBE
104-157 (ABOVE 08H)

FIGURE V.D
PICTURE 6



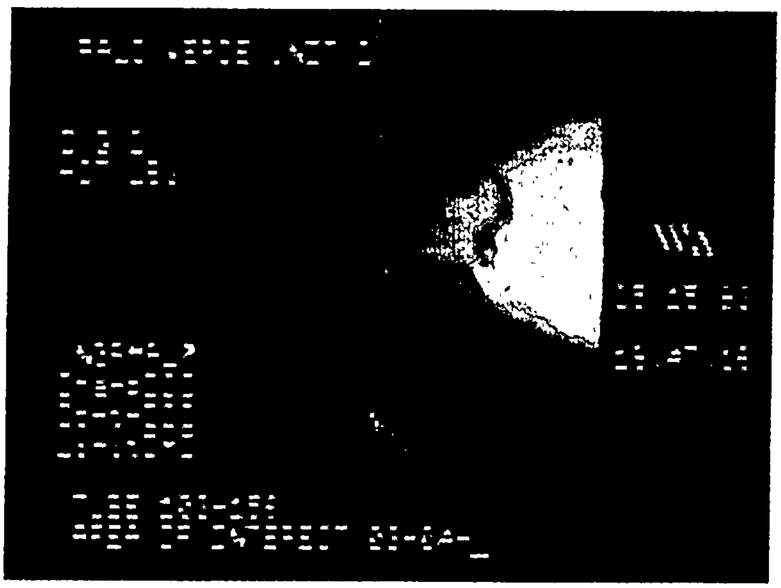
RIDGE DEPOSIT ON TUBE
104-157 (ABOVE 08H)

FIGURE V.D
PICTURE 7



GENERAL "FLAKE TYPE"
DEPOSIT ABOVE 03H

FIGURE V.D
PICTURE 8



GENERAL "FLAKE TYPE"
DEPOSIT ABOVE 03H

FIGURE V.E.1

F = Axial Flaw
D = Deposit
X = Axial Flaw W/Deposit
W = Wear

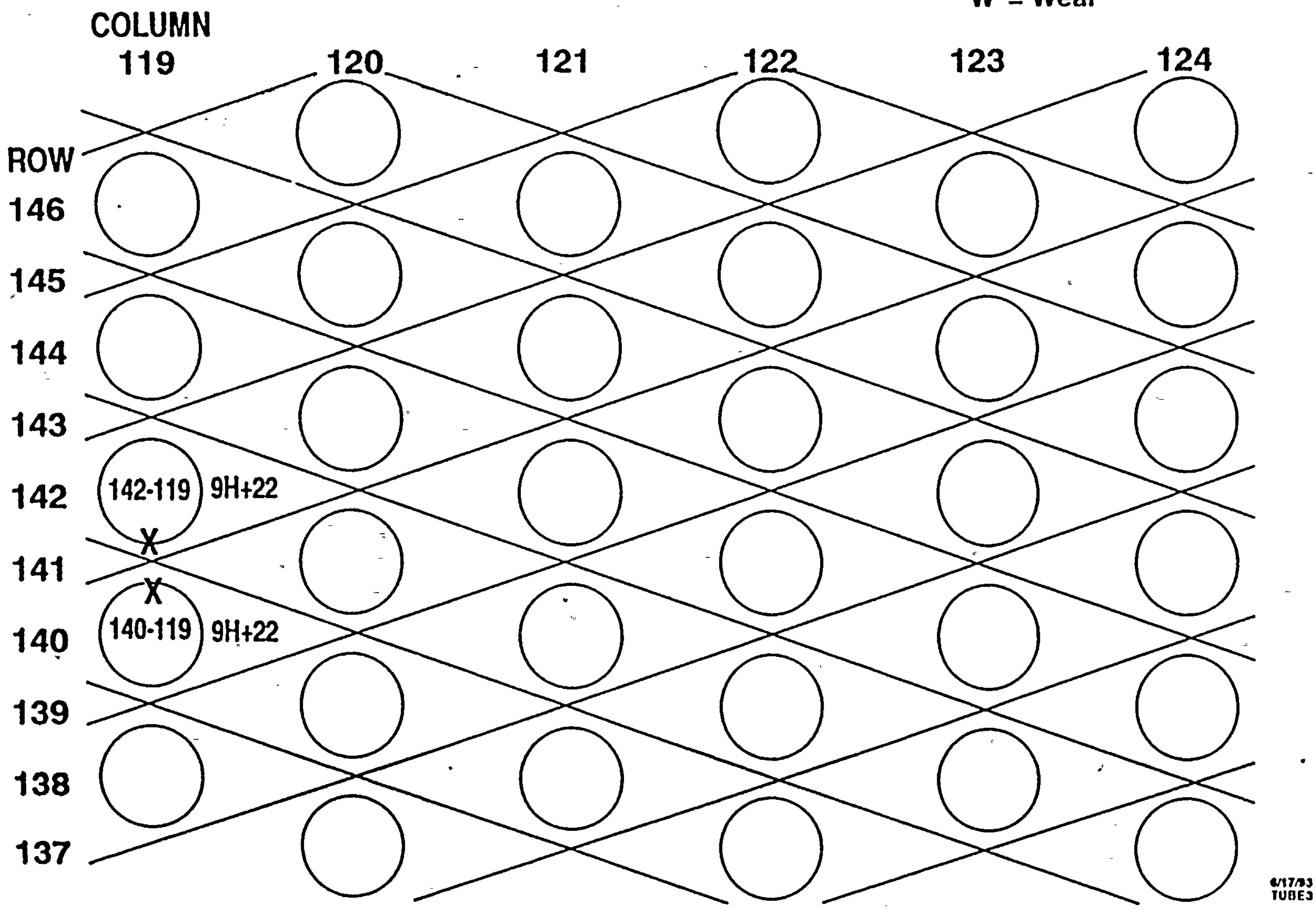


FIGURE V.E.2

F = Axial Flaw
D = Deposit
X = Axial Flaw W/Deposit
W = Wear

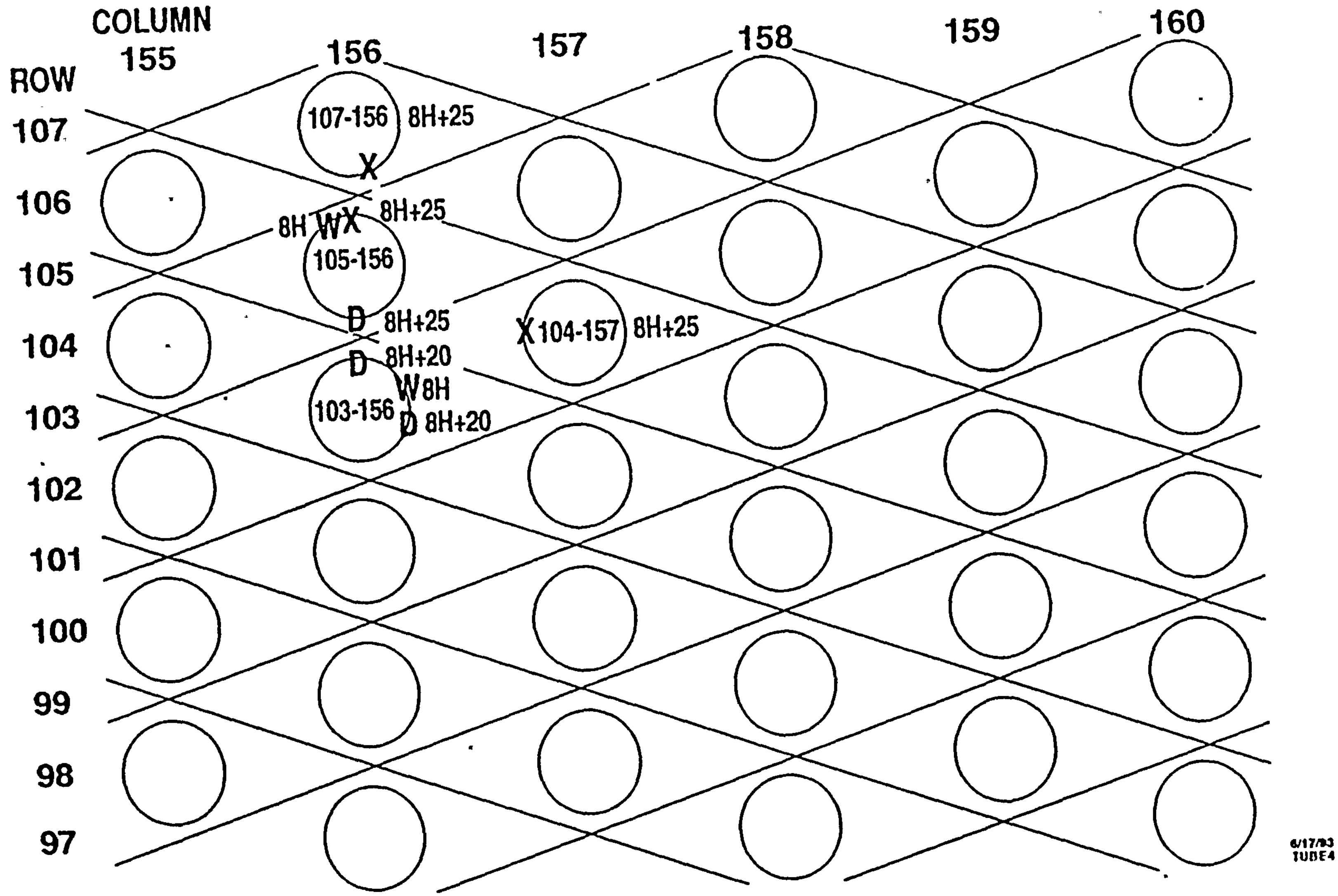


FIGURE V.E.3

F = Axial Flaw
D = Deposit
X = Axial Flaw W/Deposit
W = Wear

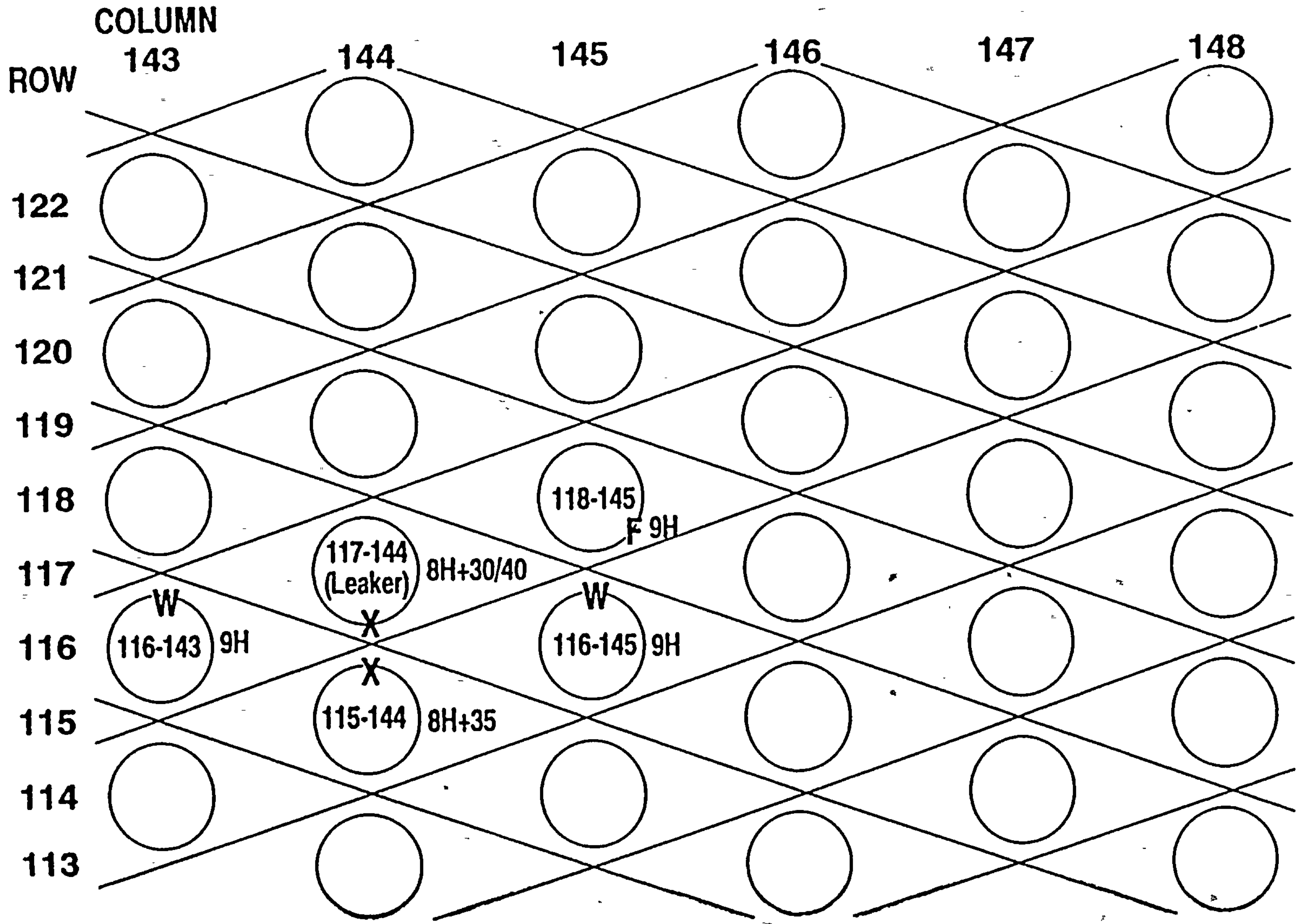


FIGURE V.E. 4

F = Axial Flaw
D = Deposit
X = Axial Flaw W/Deposit
W = Wear

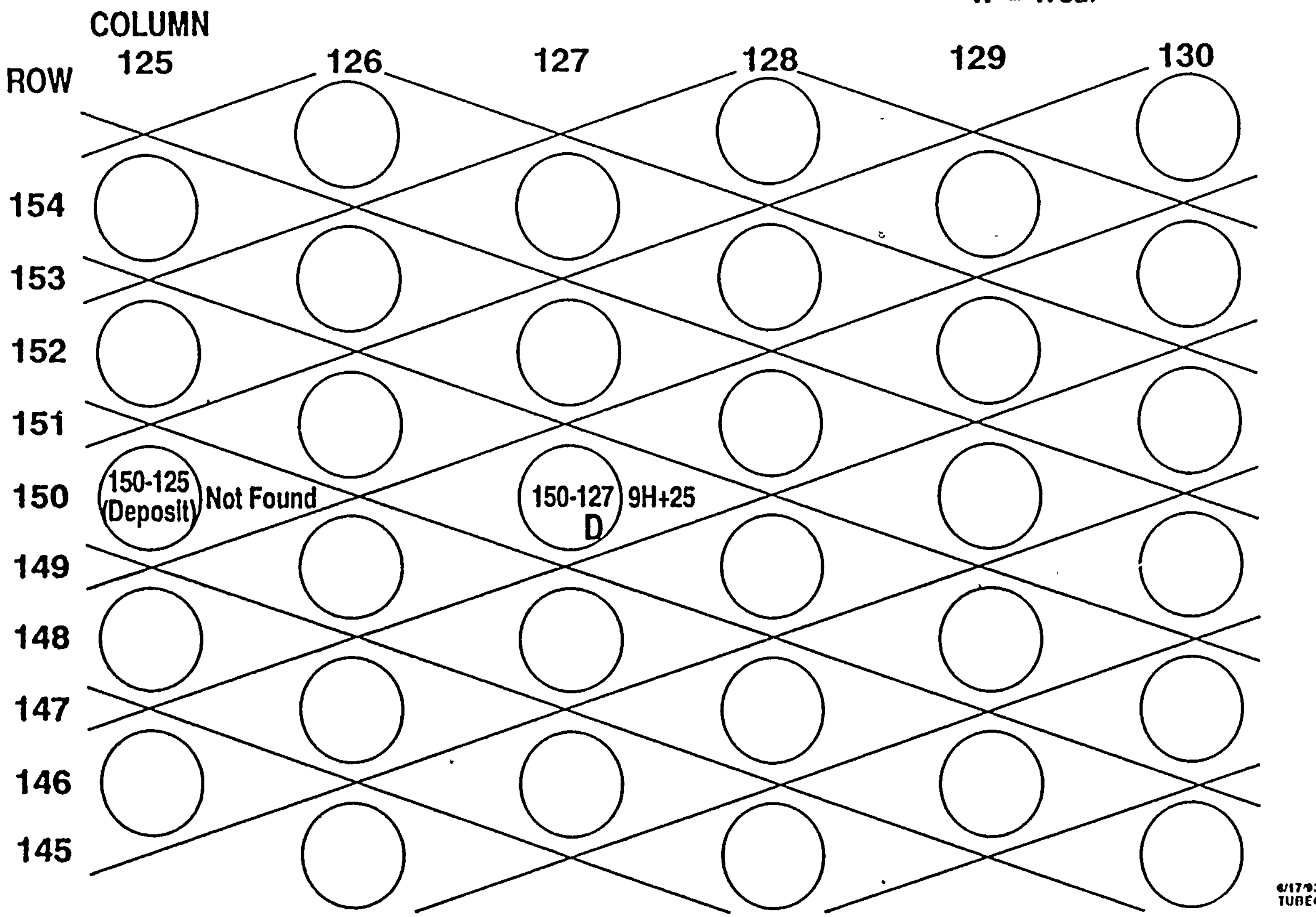


FIGURE V.E.5

F = Axial Flaw
D = Deposit
X = Axial Flaw W/Deposit
W = Wear

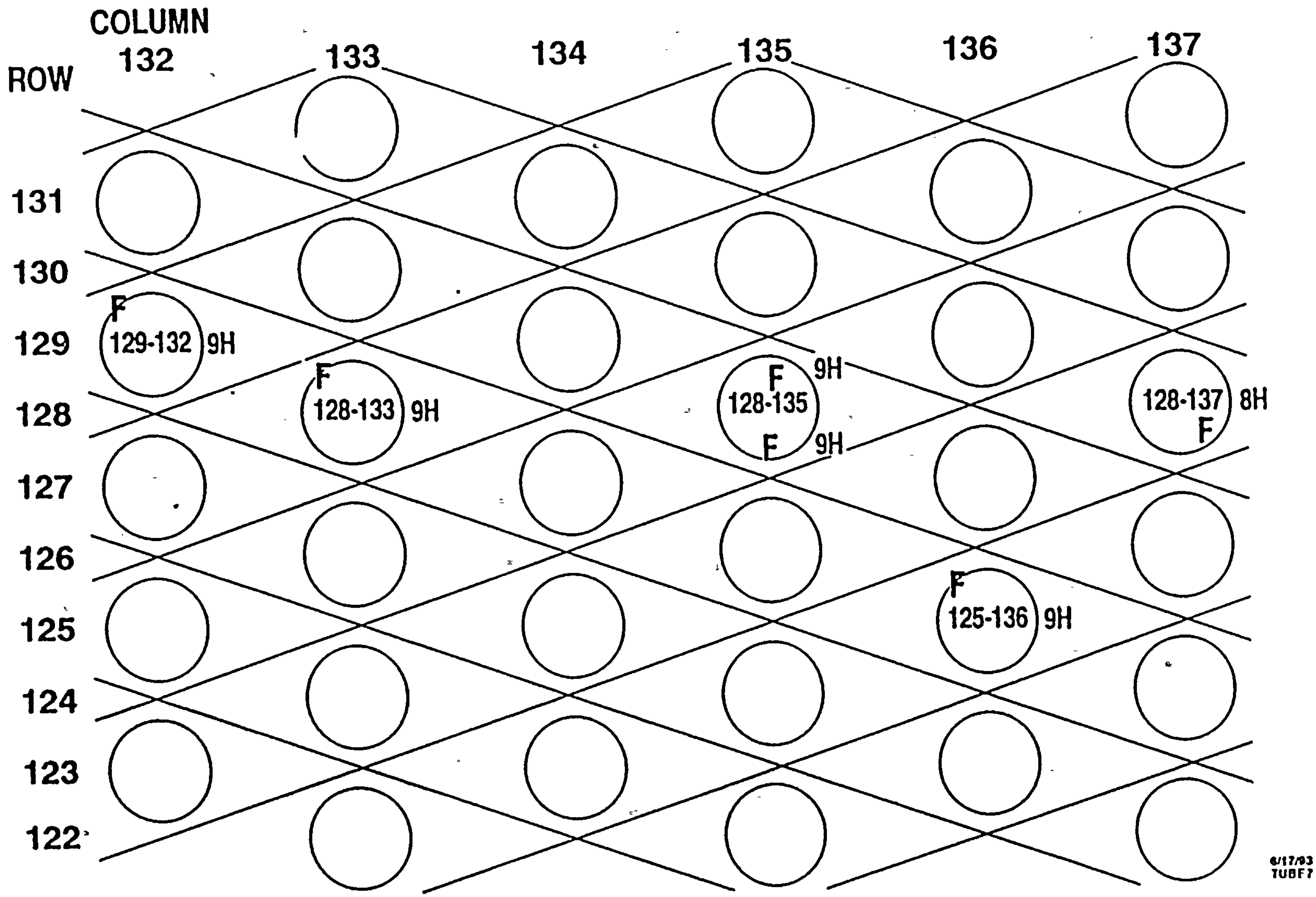


FIGURE V.E.6

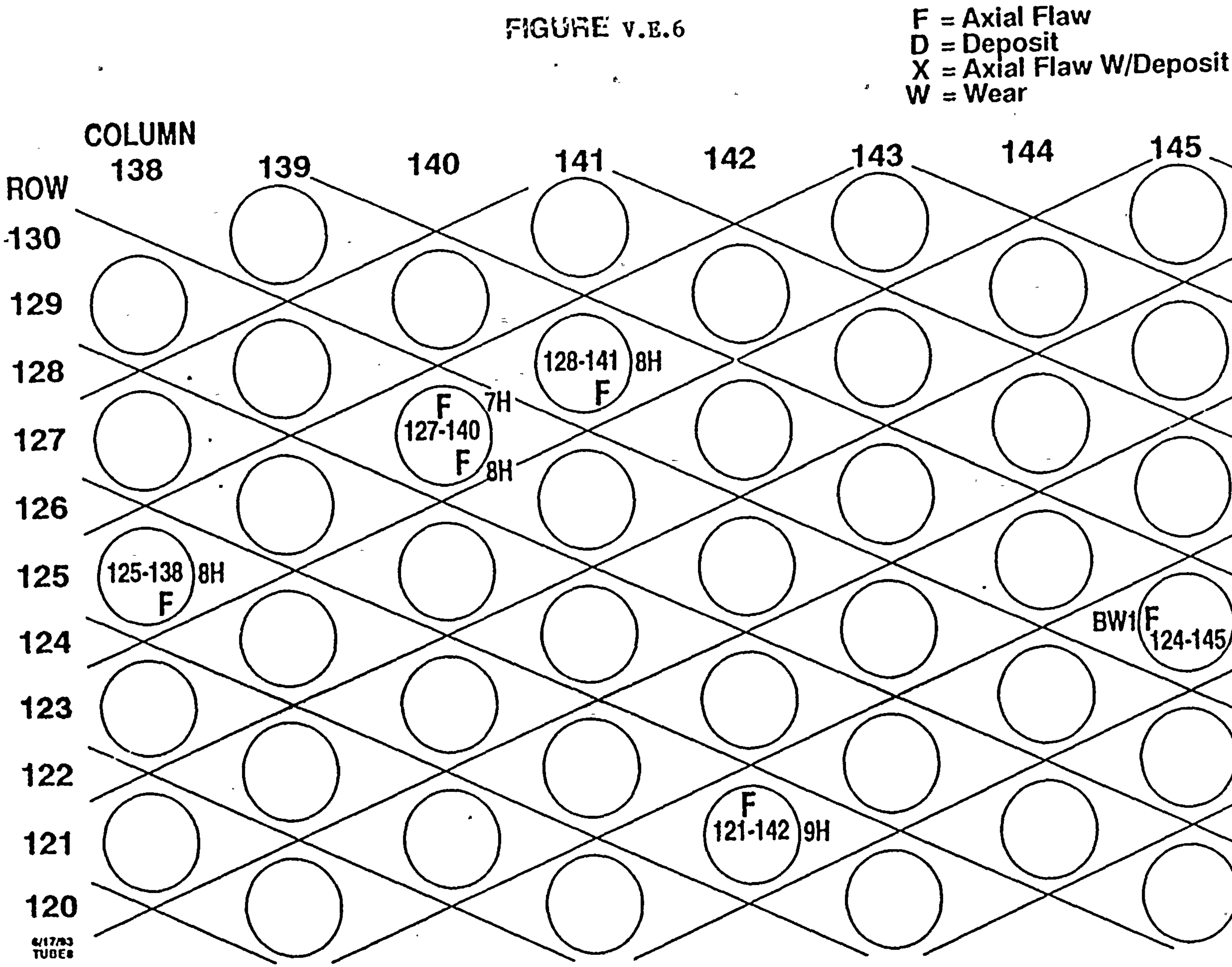

F = Axial Flaw
D = Deposit
X = Axial Flaw W/Deposit
W = Wear
COLUMN
138
139
140
141
142
143
144
145
ROW
130
129
128
127
126
125
124
123
122
121
120
128-141 8H
F
F 7H
127-140
F 8H
125-138 8H
F
BW1 F
124-145
F
121-142 9H
6/17/93
TUBES

FIGURE V.E.7

F = Axial Flaw
D = Deposit
X = Axial Flaw W/Deposit
W = Wear

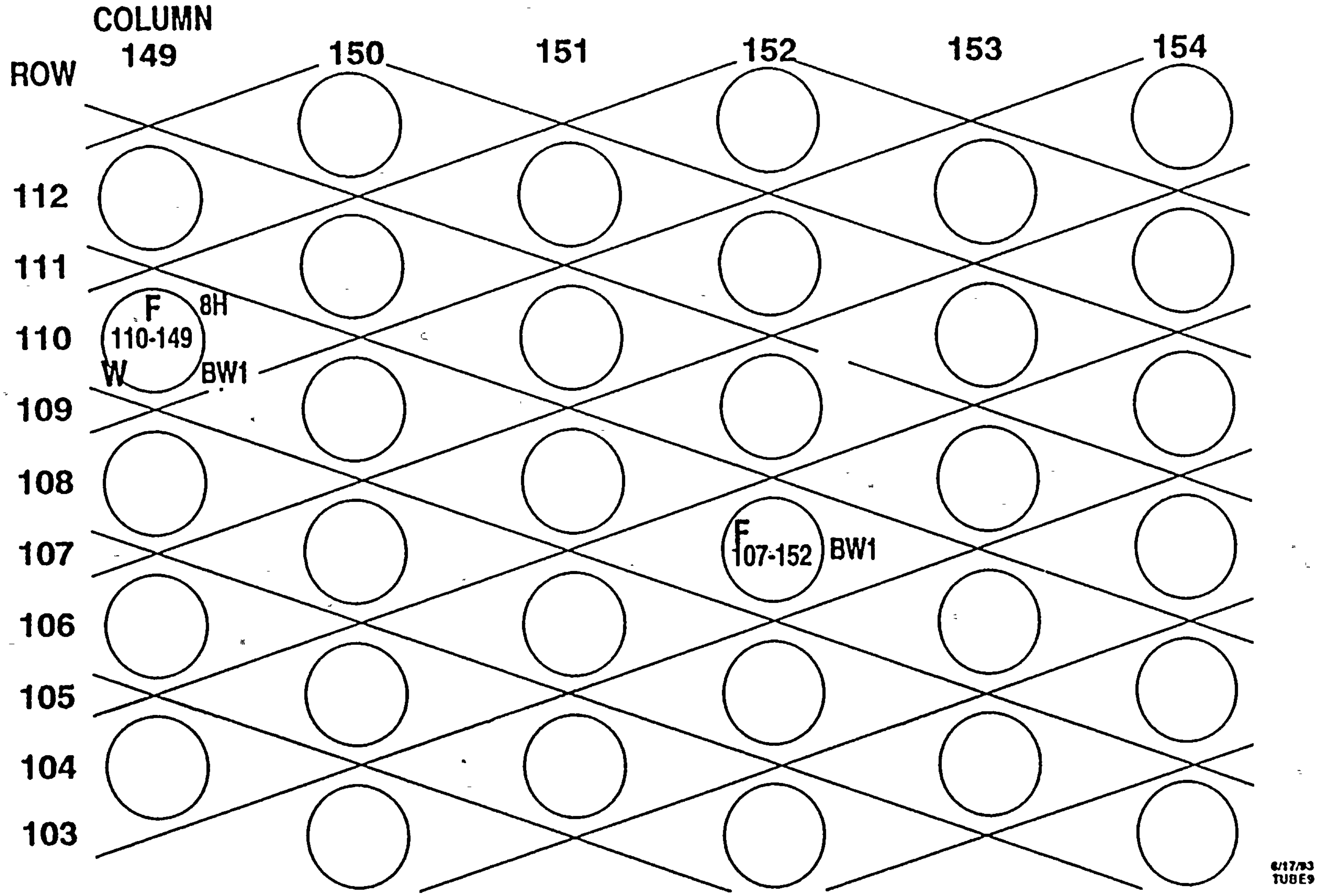


FIGURE V.E.8

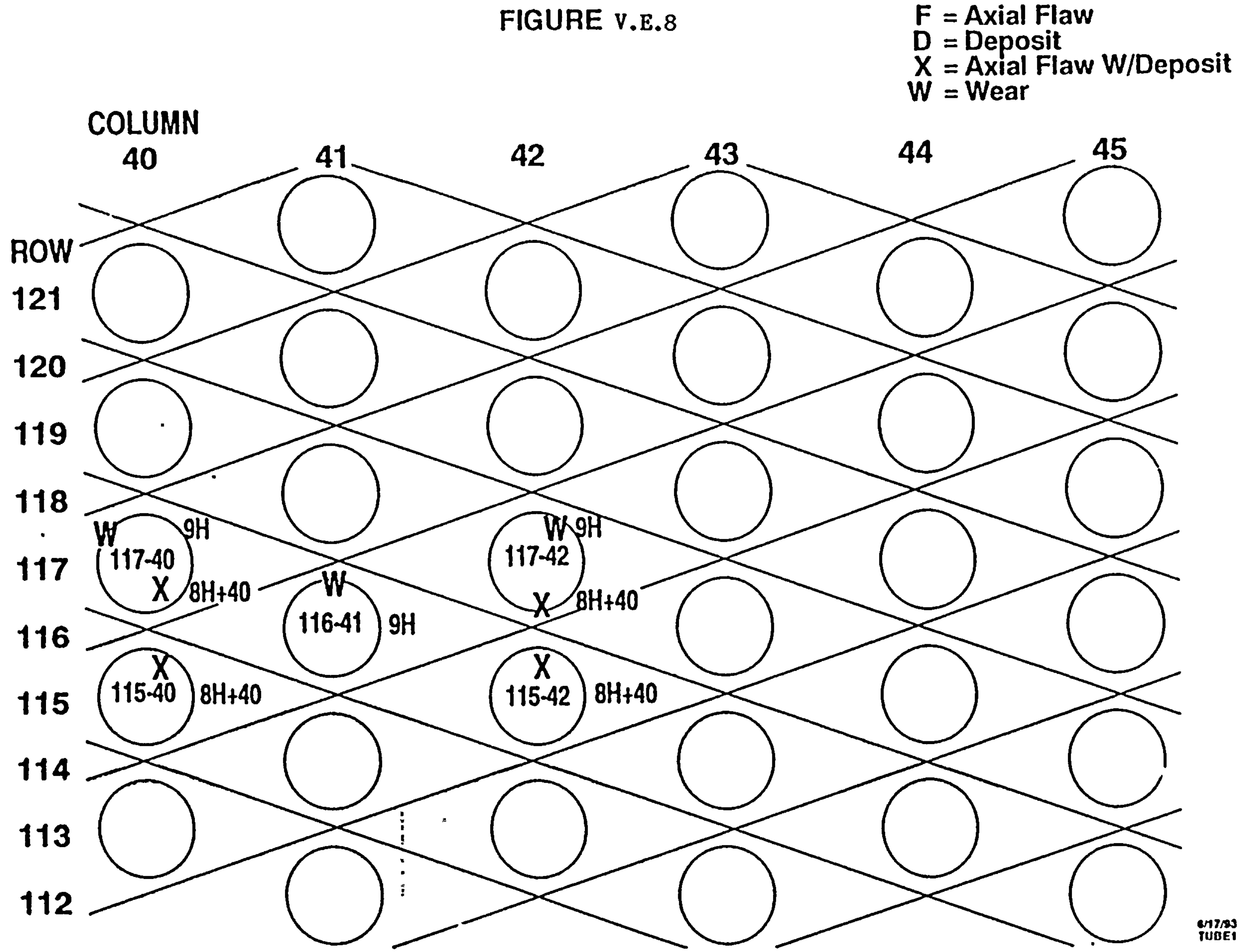

F = Axial Flaw
D = Deposit
X = Axial Flaw W/Deposit
W = Wear
COLUMN
40
41
42
43
44
45
ROW
121
120
119
118
117
116
115
114
113
112
W
9H
117-40
X
8H+40
W
116-41
9H
W
9H
117-42
X
8H+40
X
115-40
8H+40
X
115-42
8H+40
6/17/93
TUBE1

FIGURE V.E.9

F = Axial Flaw
D = Deposit
X = Axial Flaw W/Deposit
W = Wear

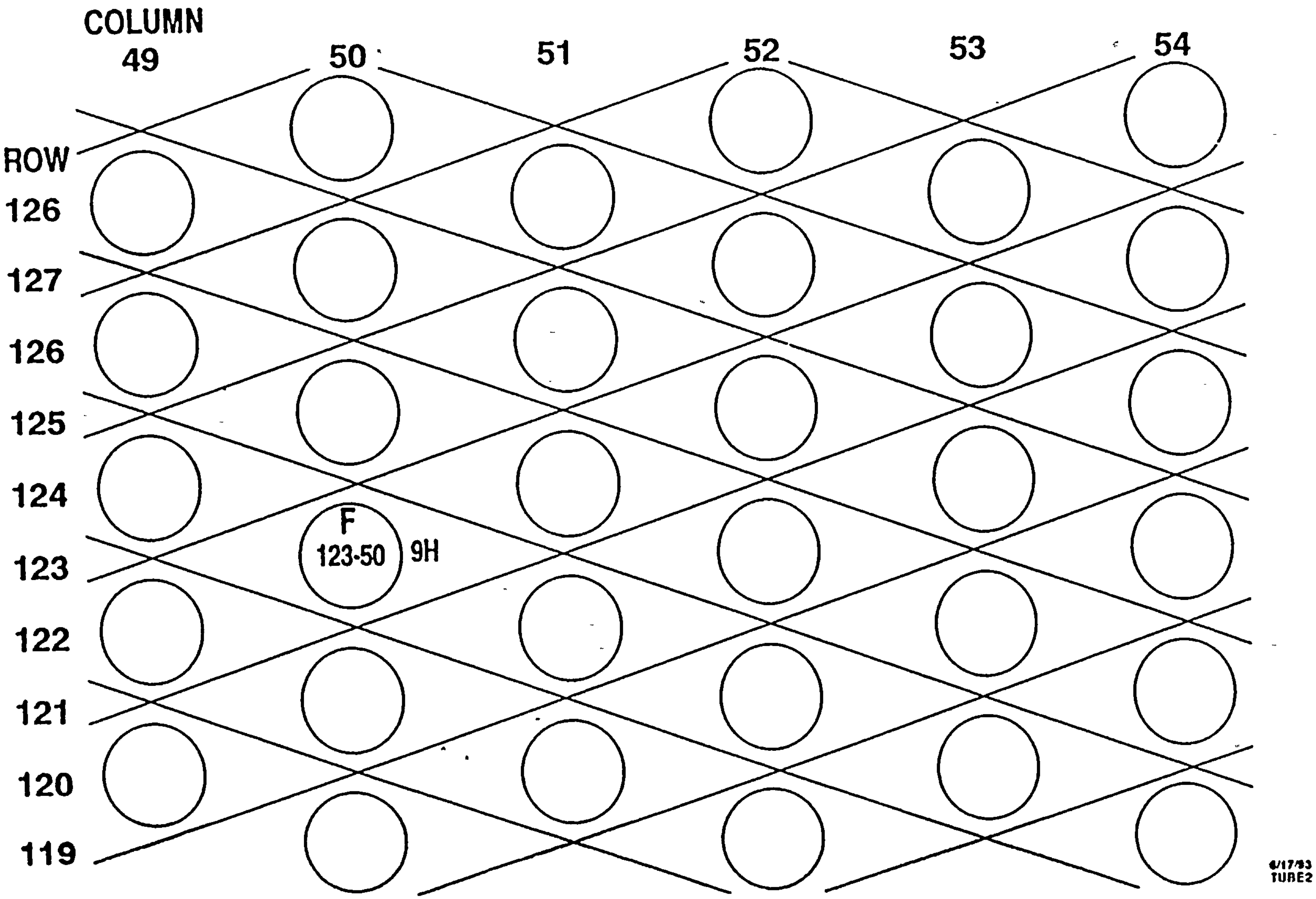


Table V.E.1

PALO VERDE UNIT 2
SG 22 ORIENTATION TEST

ROW	COL	ELEV	T Pull*	Axial Flaw	Deposit	Wear	MRPC Not Bobbin
103	156	8H+20	P	X	X(2)	X	X
		8H				X	
104	157	8H+25	S	X	X		
105	156	8H+25	P	X	X(2)		
		8H				X	
107	152	BW1		X			
107	156	8H+25		X	X		
110	149	8H	S	X			
		BW1		X			
115	40	8H+40		X	X		
115	42	8H+40		X	X		
115	144	8H+35		X	X		
116	41	9H	P			X	
116	143	9H	S			X	
116	145	9H	S			X	
117	40	8H+40	P	X		X	X
		9H					
117	42	8H+40	S	X	X		
		9H				X	
117	144	8H+40	P	X	X		
118	145	9H		X			
121	142	9H		X			
123	50	9H		X			

*Tube Pull - (P) Primary tube pull candidates.
(S) Secondary tube pull candidates.

NOTE: Tubes 22-13 and 29-24 were pulled but indications at the 01H were not tested for orientation

Table V.E.1

PALO VERDE UNIT 2
SG 22 ORIENTATION TEST

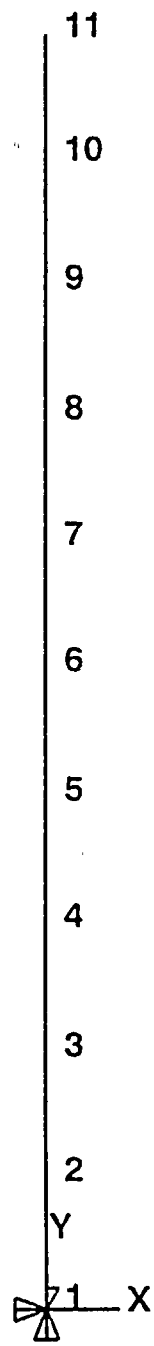
ROW	COL	ELEV	T Pull*	Axial Flaw	Deposit	Wear	MRPC Not Bobbin
124	145	BW1		X			
125	136	9H		X			
125	138	8H	S	X			
127	140	8H	P	X			
		7H		X			
128	133	9H		X			
128	135	9H		X			
128	137	8H	S	X			
128	141	8H		X			
129	132	9H		X			
140	119	9H+22		X	X		
142	119	9H+22		X	X		
150	125	9H+25			X		
150	127	9H+25			X		

*Tube Pull - (P) Primary tube pull candidates.
(S) Secondary tube pull candidates.

NOTE: Tubes 22-13 and 29-24 were pulled but indications at the 01H were not tested for orientation

FIGURE V.F.1

Straight Tube FEA Model



Buckling of tube under axial load at batwing

7993
MODEL-2

FIGURE V.F.2

U-Bend Tube FEA Model

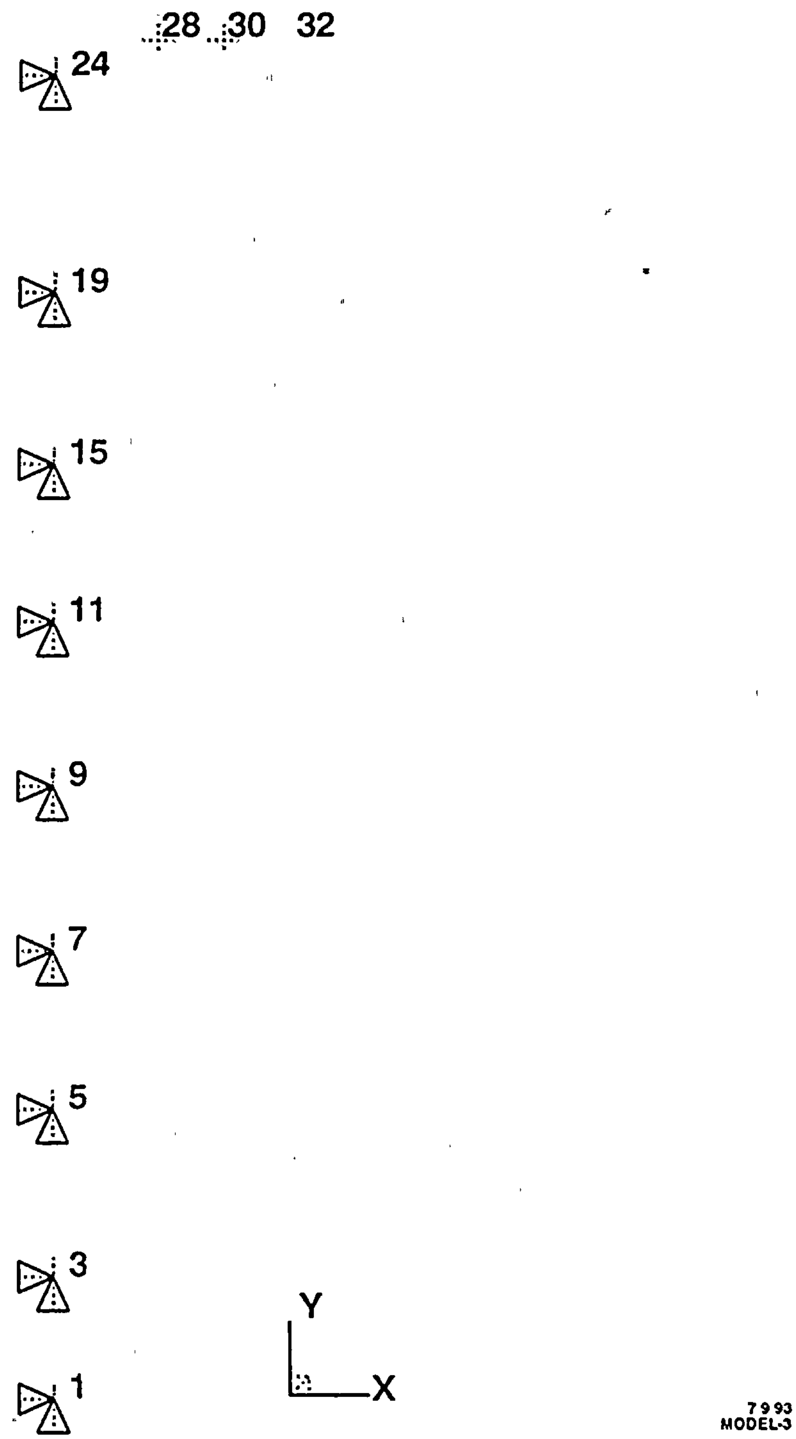


FIGURE V.F.3

Deformations of Tube Assuming Sideway Possible

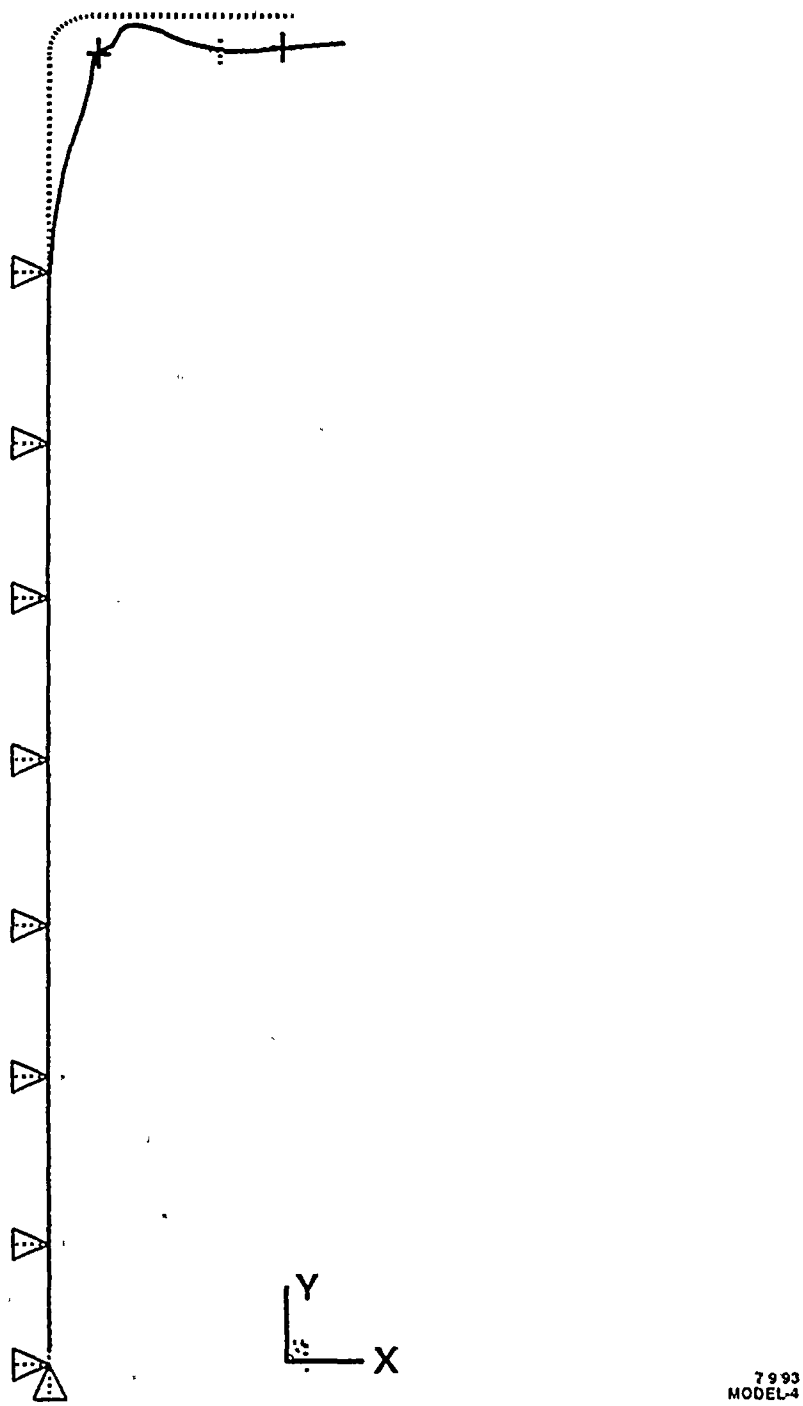


FIGURE V.F.4

Deformations of Tube Assuming No Sideway

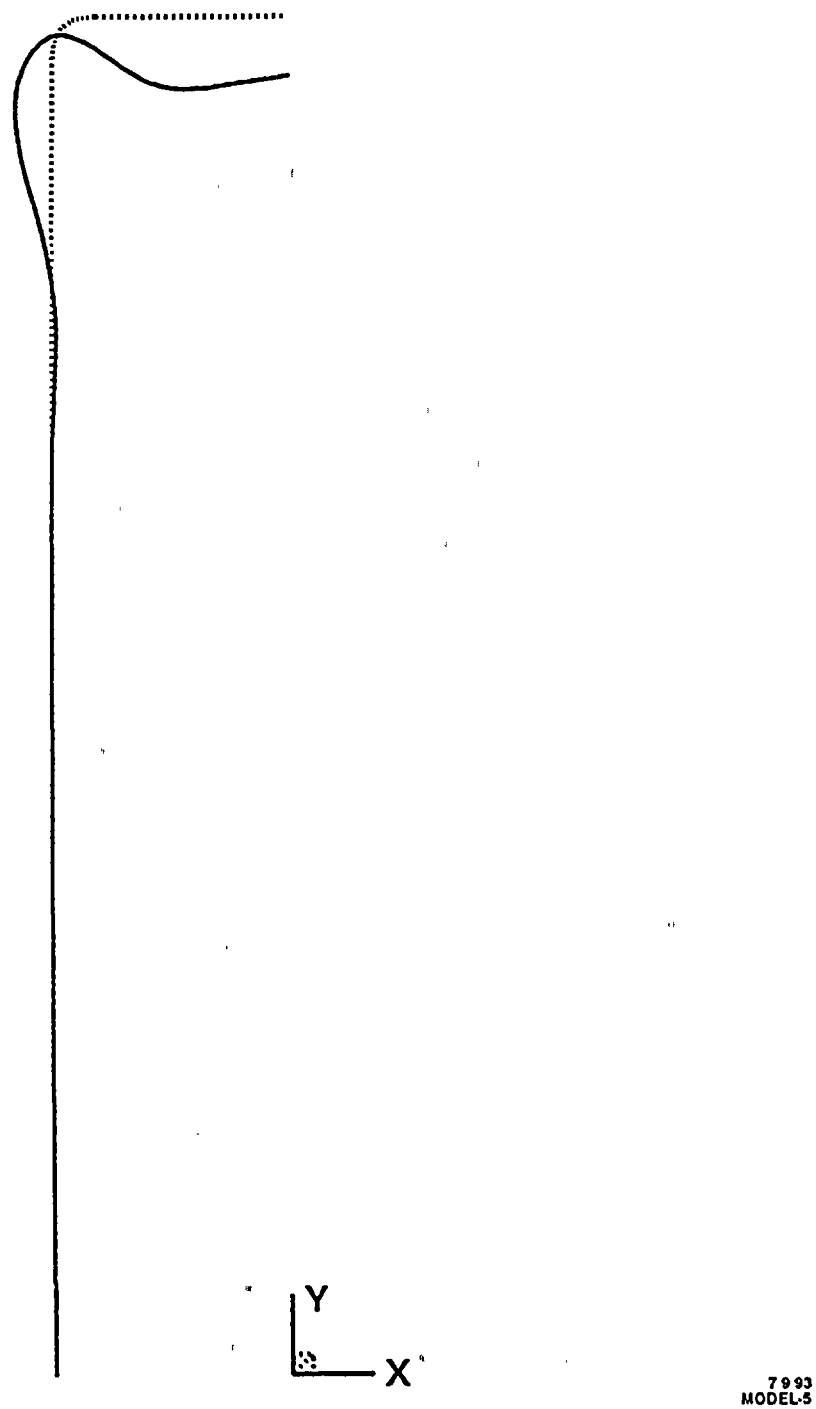
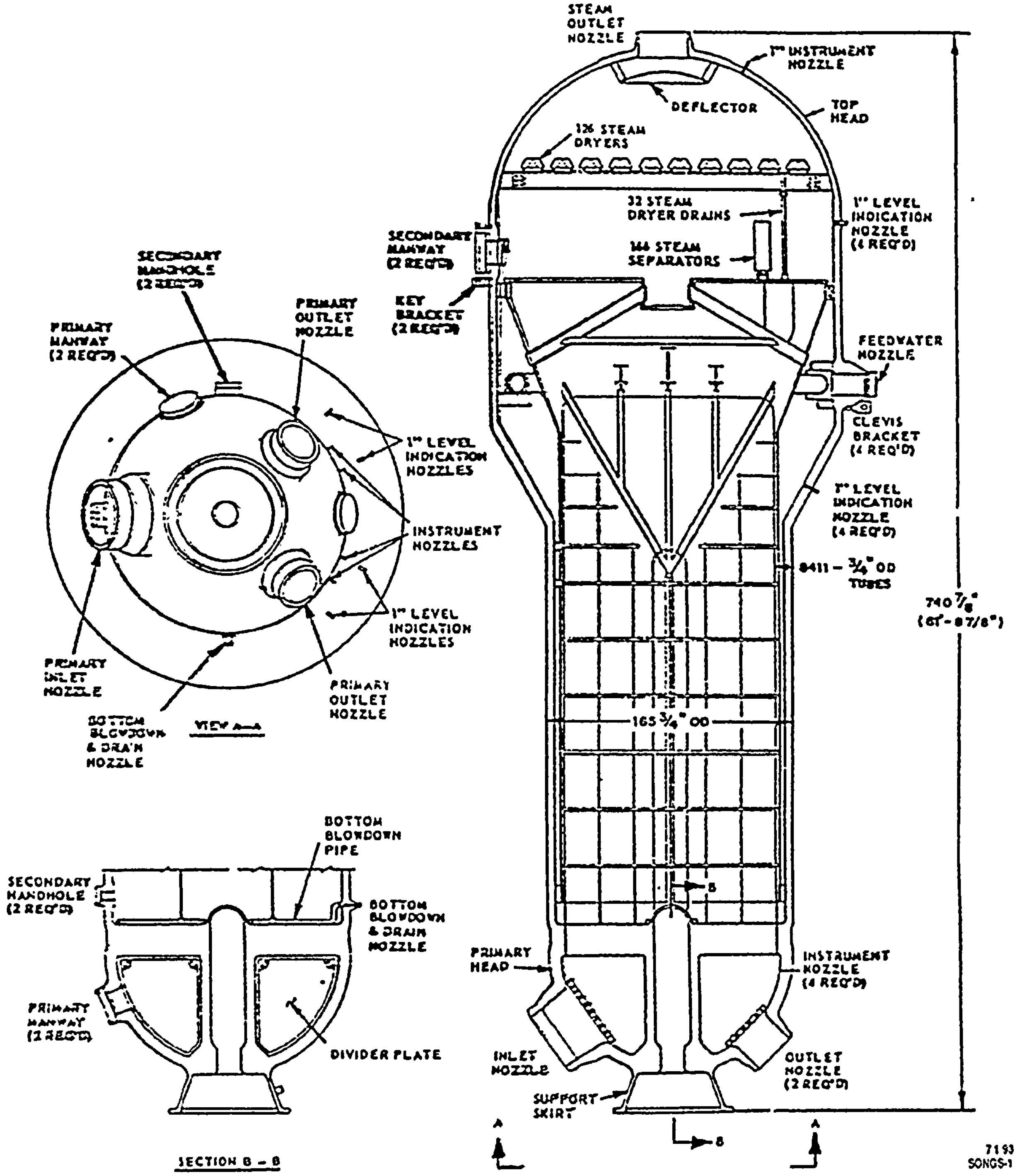


FIGURE V.F.5

St. Lucie-1 Unit 2 Steam Generator
(Similar to the Series 67)



7193
SONGS-1

FIGURE V.F.7

ABB-CE Ventilated Vertical Tube Support Grid

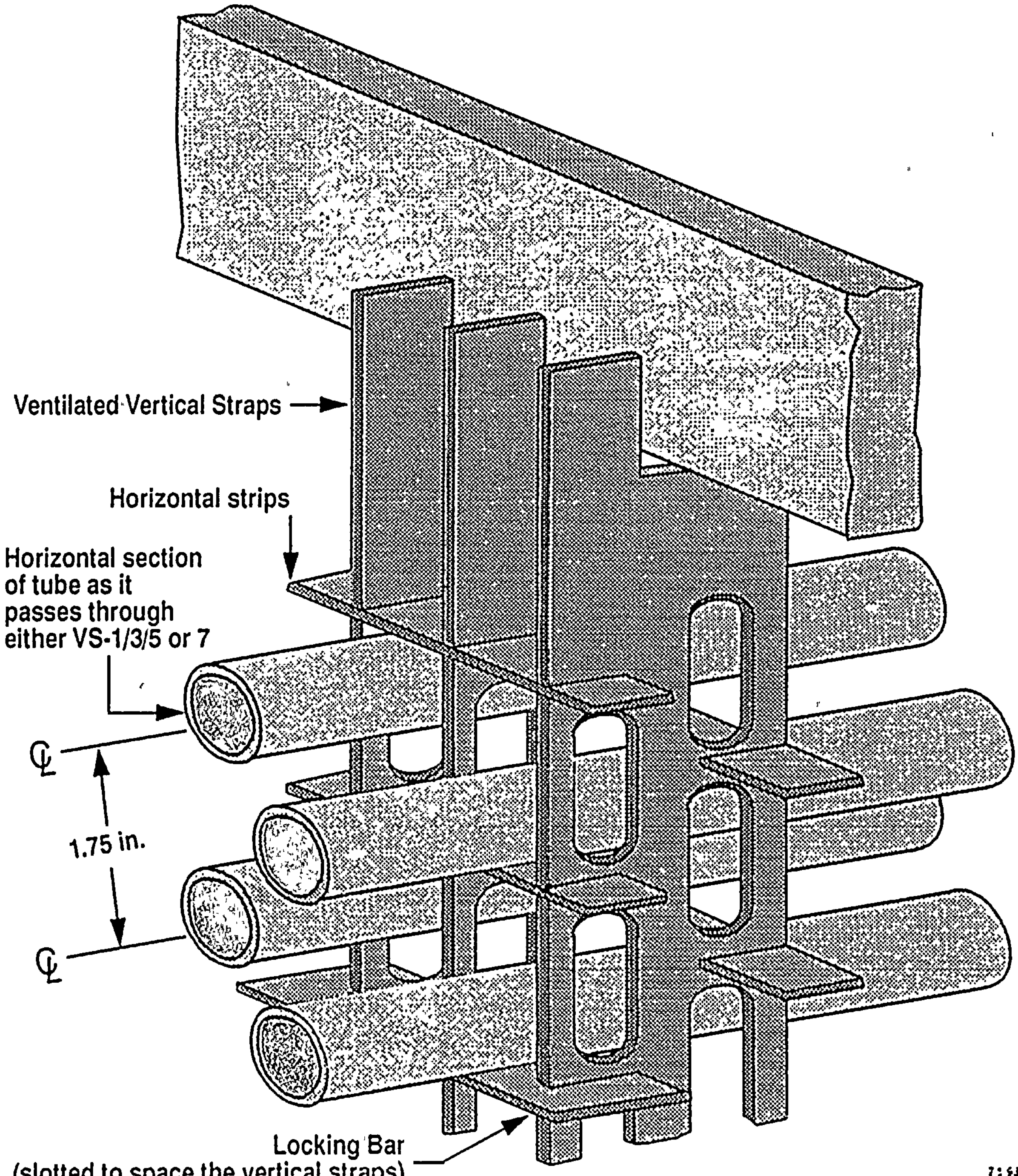
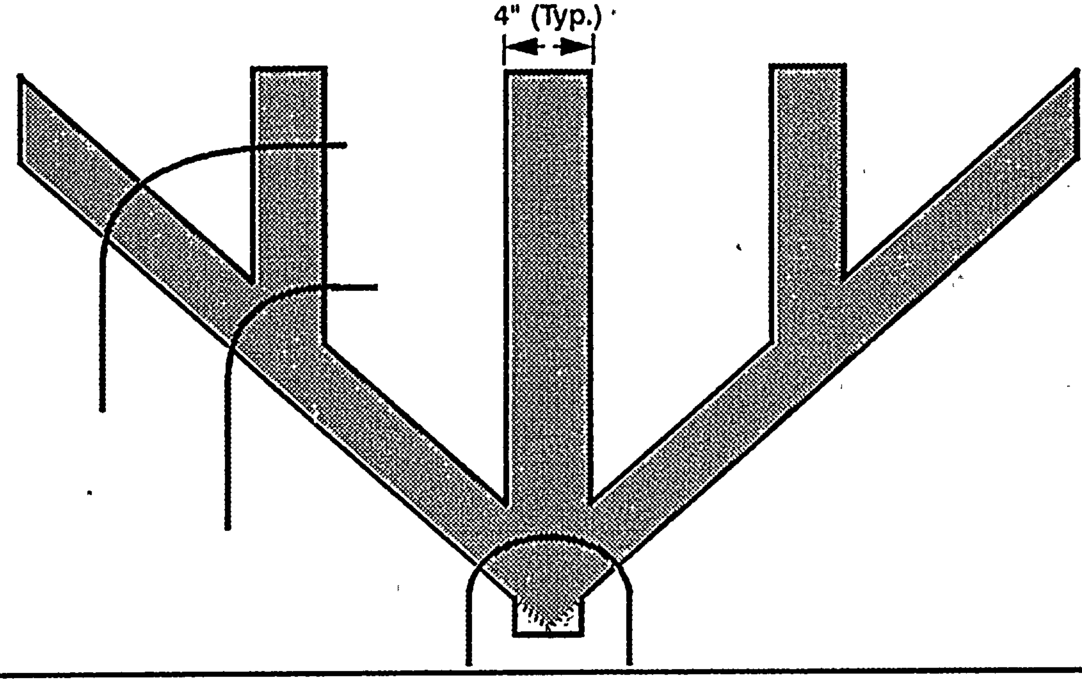
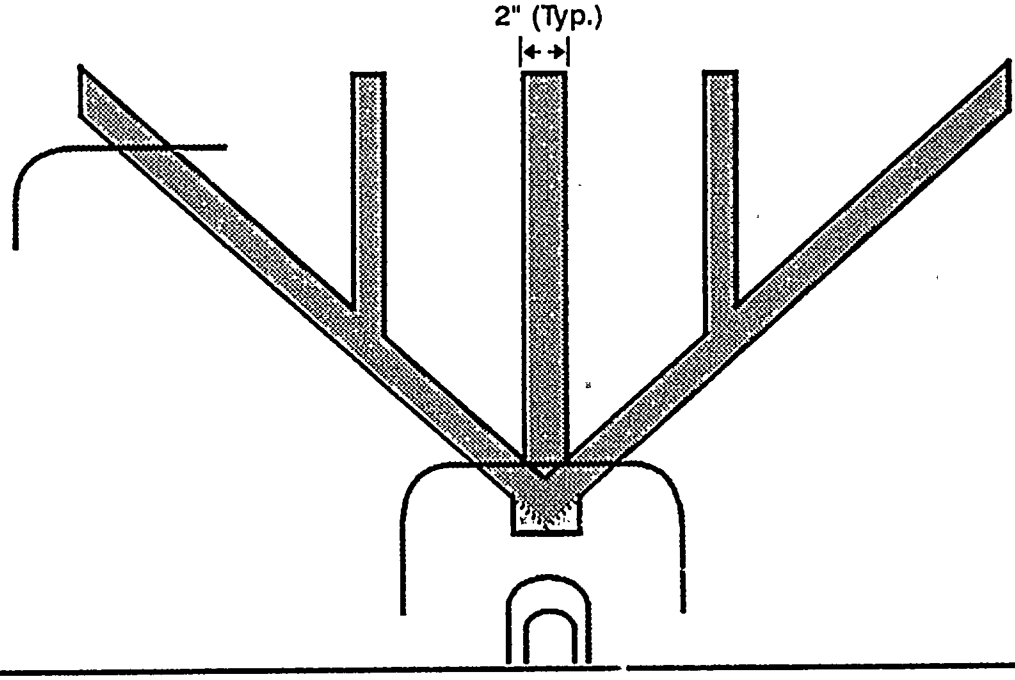


FIGURE V.F.8

Series 67 Unibody



Arkansas Nuclear One - Unit 2 Unibody



7 1 93
UNIBODY

FIGURE V.F.9

Upper Tube Bundle Geometry Hot Side (90° - 270° Axis)

= Relatively long unsupported length

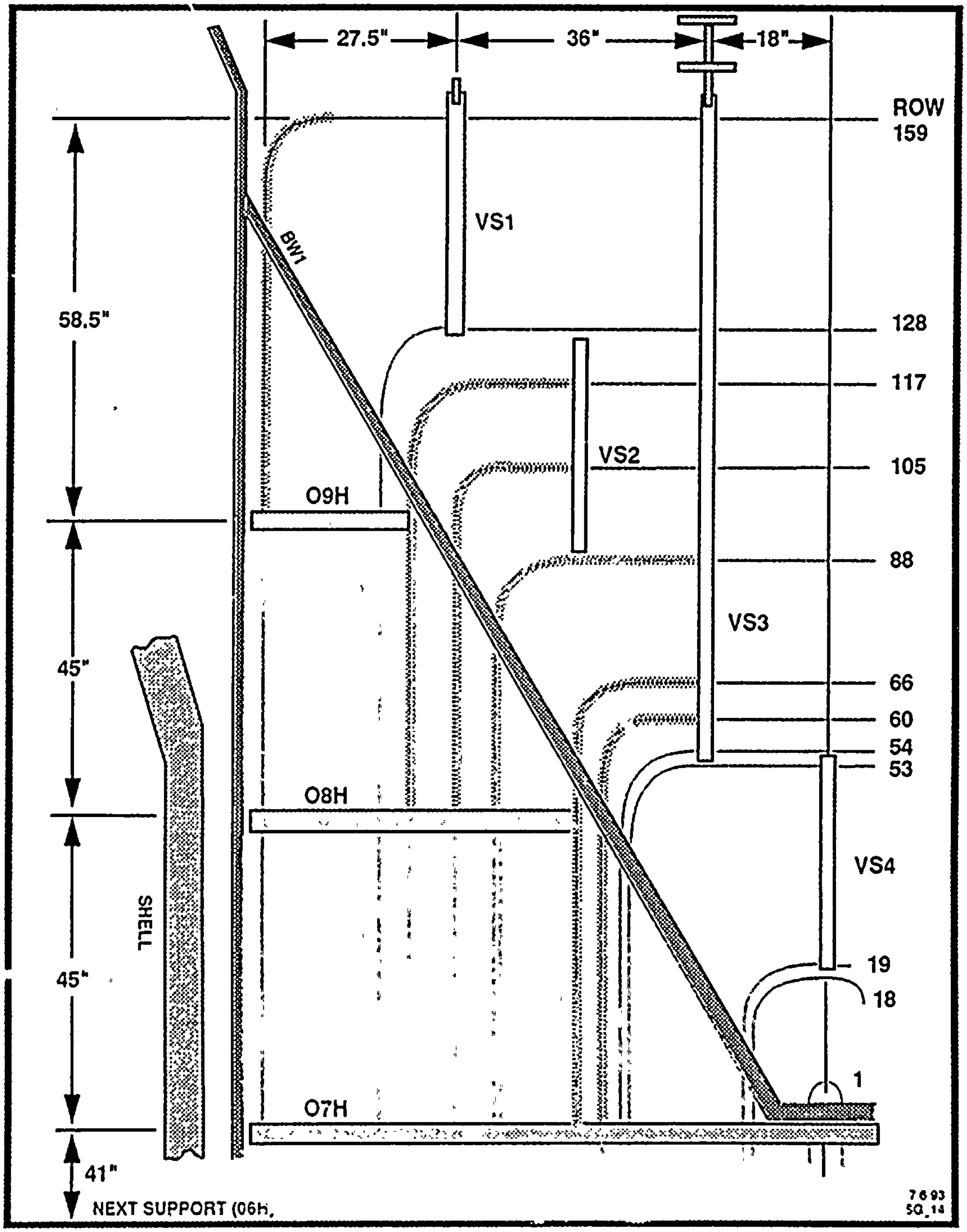


FIGURE V.F.10

San Onofre Units 2 & 3 Bend Region Tube Supports
(Typical of the 3410 Series)

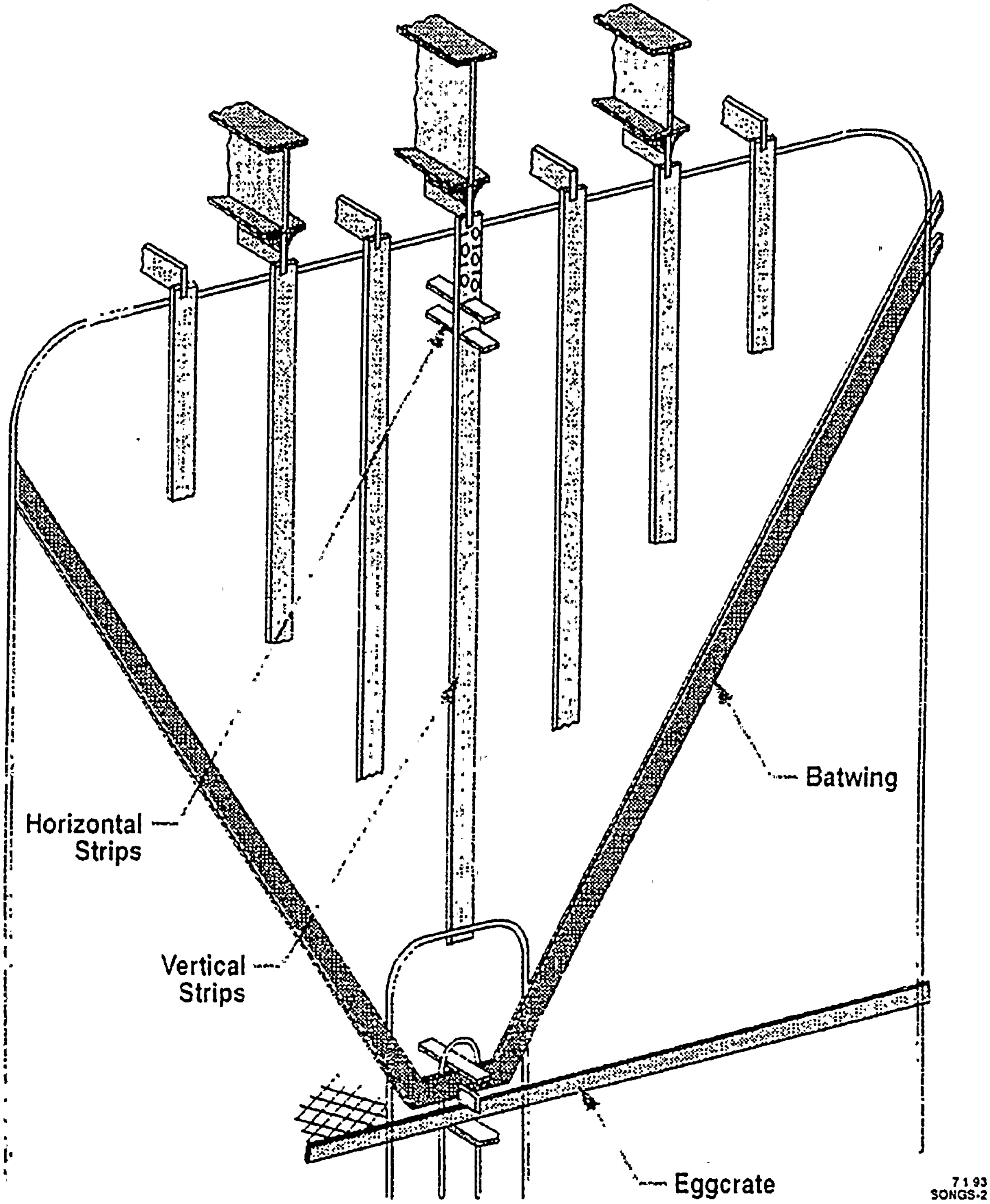


FIGURE V F.11

Palo Verde Upper Tube Bundle Supports

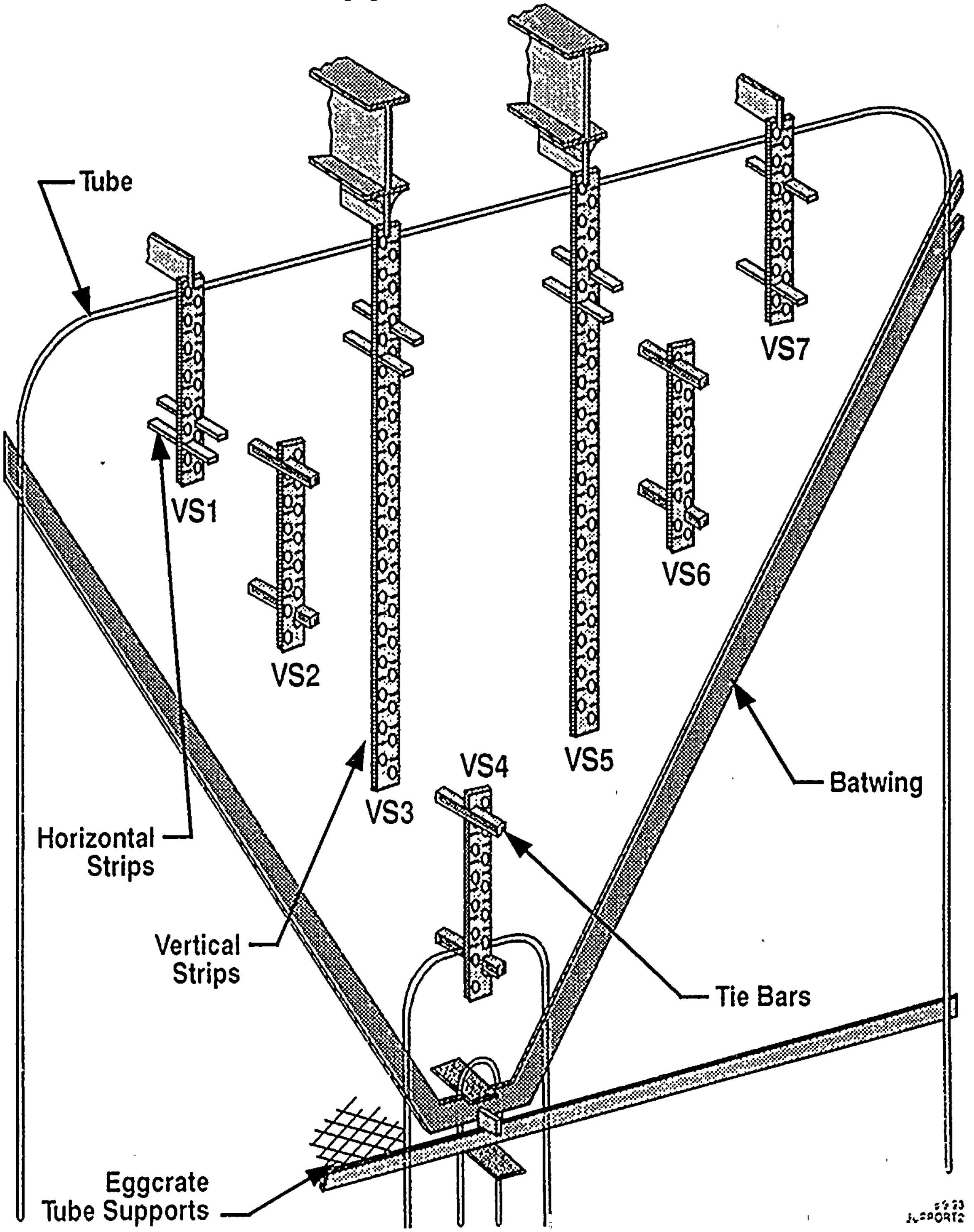


Table V.1.1

PALO VERDE STEAM GENERATOR OPERATING CONDITIONS
100% POWER

1. Steam Pressure	1070 psia
2. Feedwater Flow Rates	
Economizer	2147.5 lb/sec
Cold Side Downcomer	238.5 lb/sec
Total	2386 lb/sec
3. Feedwater Temperature	450°F
4. Primary Flow Rate	22,778 lb/sec
5. Primary Pressure	2250 psia
6. Thermal Output	1906 MW
7. Downcomer Level	
NWL	449.72 inch
NWL + 5% NR	457.25 inch
NWL - 5% NR	442.19 inch

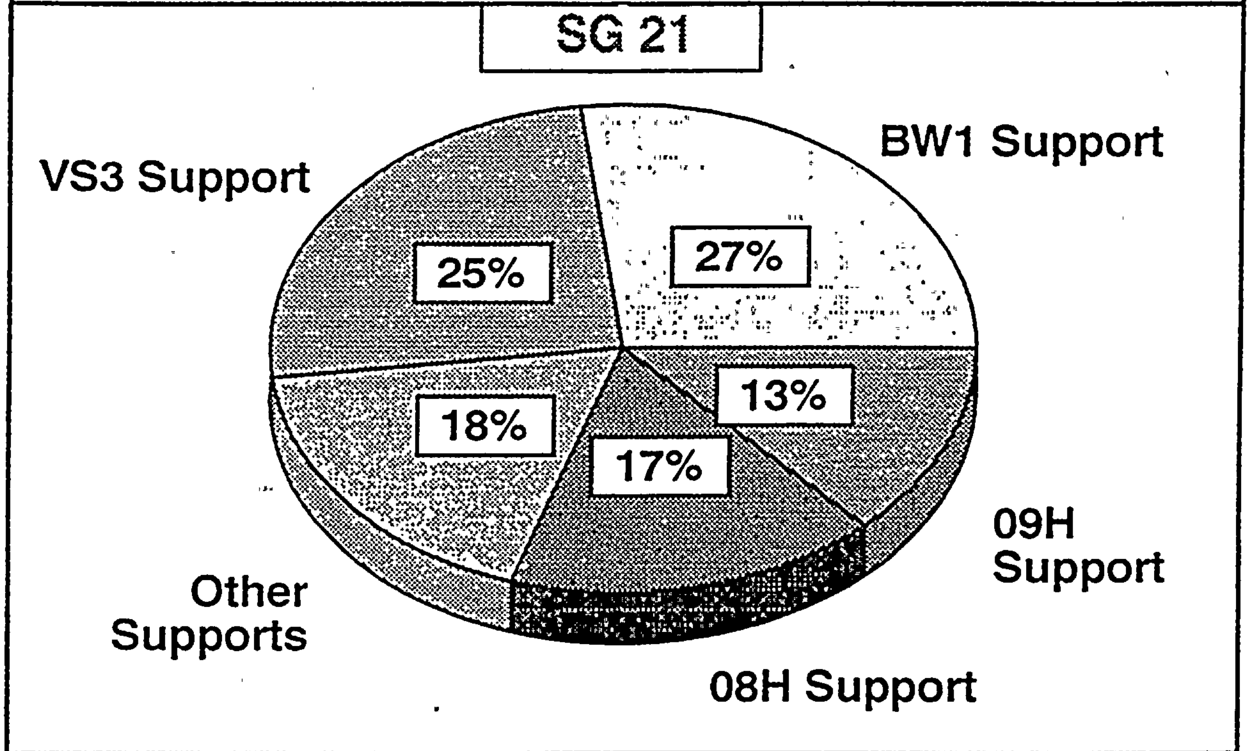
Table V.I.2

ABB-CE PROPRIETARY

TABLE V.I.3

FIGURE V.J.1

Steam Generator Total Wear Indications (Over 20%)



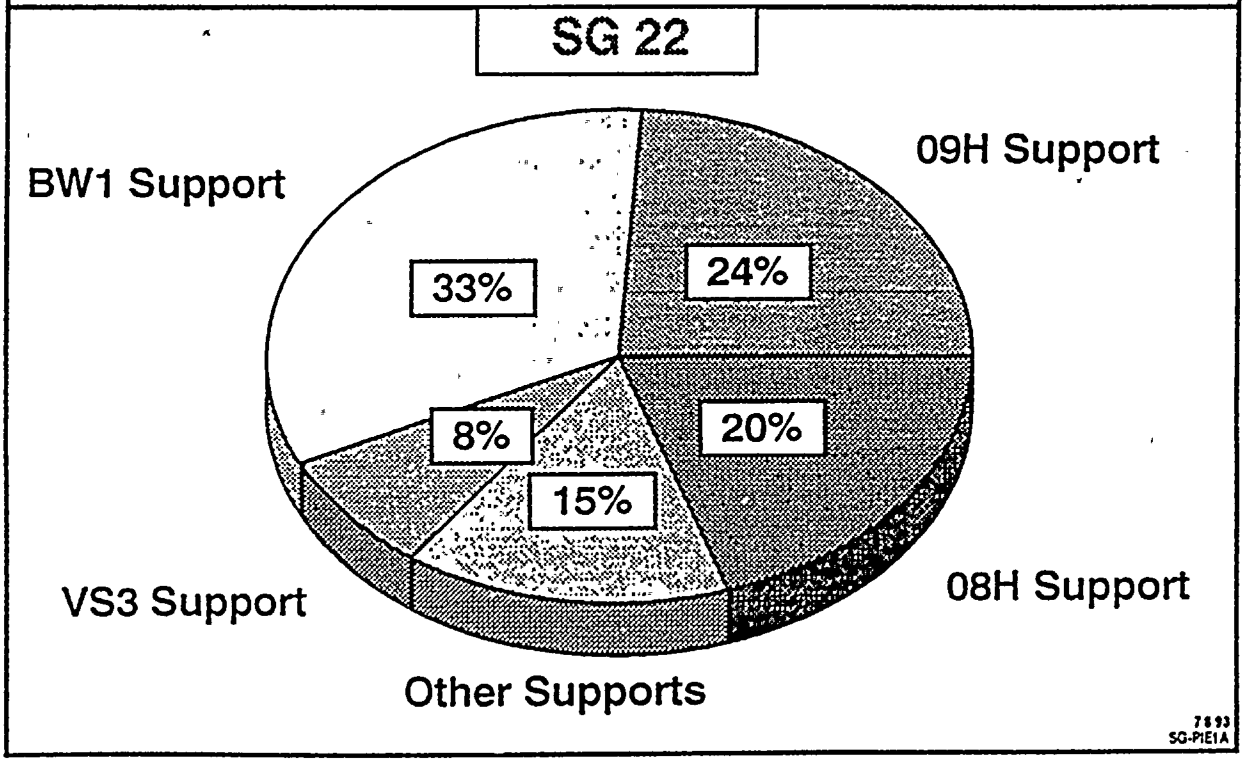


FIGURE V.J.2

Steam Generator New Wear Indications (Over 20%)

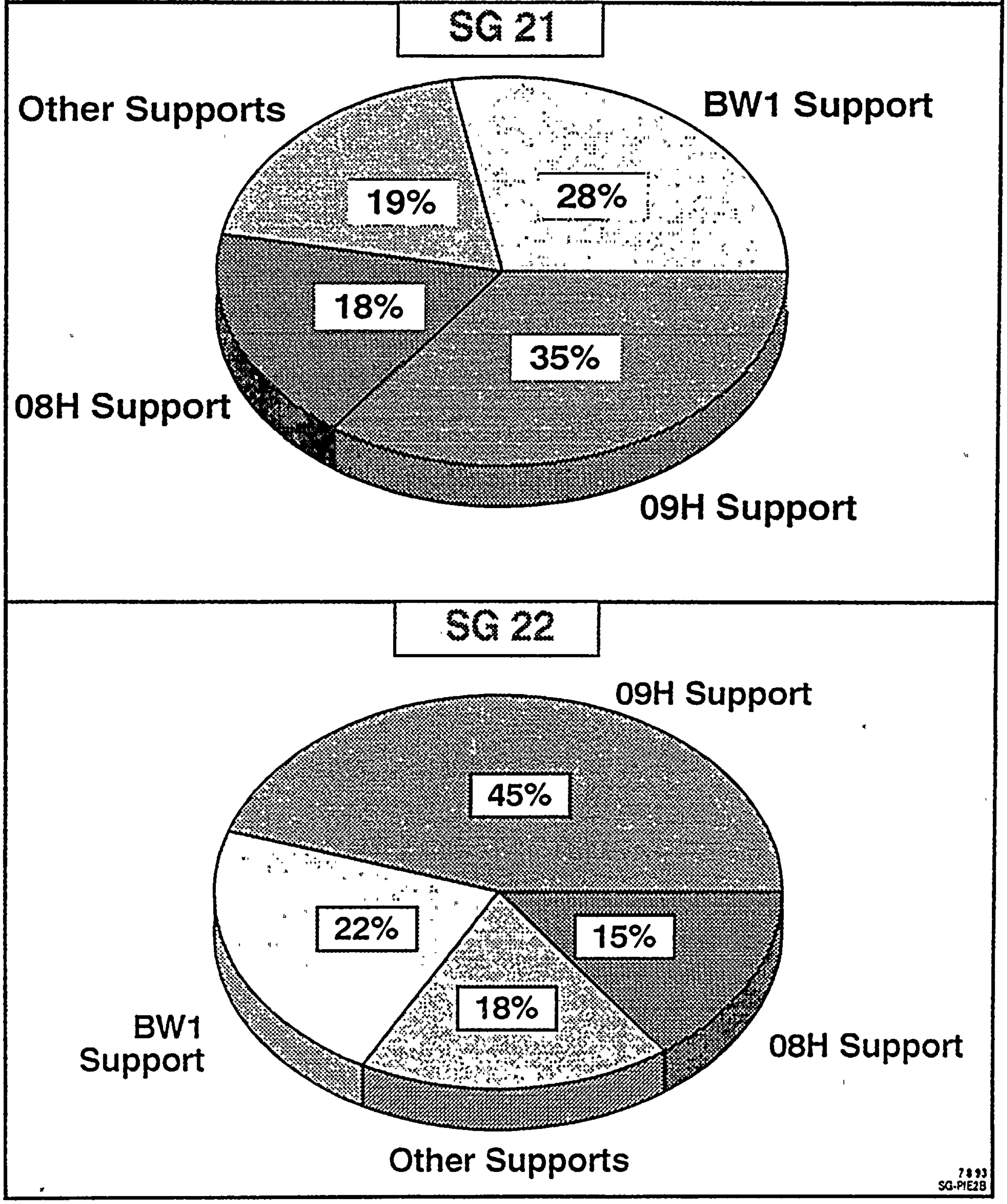


Table V.J.1

STEAM GENERATOR WEAR STUDY
SG 21

GENERATOR 21 WEAR CHANGE STUDY	09H Scallop
Total Number of Wear Indications at Support	24
Average Change in Wear Depth (% Throughwall)	25
Total Number of New Wear Indications at Support	15
Percent of New Wear Indications at Support	62%
Percent of Total Steam Generator Wear Indications	7%
Percent of Total Steam Generator New Wear Indications	19%
Percent of Total 09H Wear Indications	51%
Percent of Total 09H New Wear Indications	56%

NOTE: Wear rates determined by this study were biased high by the exclusion of data from wear indications of below 20 percent.

Table V.J.2

STEAM GENERATOR WEAR STUDY
SG 22

GENERATOR 22 WEAR CHANGE STUDY	09H Scallop
Total Number of Wear Indications at Support	54
Average Change in Wear Depth (% Throughwall)	18%
Total Number of New Wear Indications at Support	18
Percent of New Wear Indications at Support	33%
Percent of Total Steam Generator Wear Indications	33%
Percent of Total Steam Generator New Wear Indications	23%
Percent of Total 09H Wear Indications	57%
Percent of Total 09H New Wear Indications	51%

NOTE: Wear rates determined by this study were biased high by the exclusion of data from wear indications of below 20 percent.

Table V.J.3

STEAM GENERATOR WEAR STUDY
SG 21

GENERATOR 21 WEAR CHANGE STUDY	ALL SUPTS.	03C SUPT.	04H SUPT.	05C SUPT.	07C SUPT.	07H SUPT.	08C SUPT.	08H SUPT.	09C SUPT.	09H SUPT.
Total Number of Wear Indications at Support	362	1	1	1	1	5	1	62	1	47
Average Change in Wear Depth (% Throughwall)	11%	0%	3%	0%	2%	15%	31%	10%	1%	22%
Total Number of New Wear Indications at Support	78	0	0	0	0	1	1	14	0	27
Percent of New Wear Indications at Support	22%	0.00%	0.00%	0%	0%	20%	100%	22%	0%	57%
Percent of Total Steam Generator Wear Indications	100%	0.28%	0.28%	0.28%	0.28%	1.38%	0.28%	17.13%	0.28%	12.98%
Percent of Total Steam Generator New Wear Indications	100%	0.00%	0.00%	0.00%	0.00%	1.28%	1.28%	17.95%	0.00%	34.62%

GENERATOR 21 WEAR CHANGE STUDY	BW1 SUPT.	BW2 SUPT.	VS1 SUPT.	VS2 SUPT.	VS3 SUPT.	VS4 SUPT.	VS5 SUPT.	VS6 SUPT.	VS7 SUPT.
Total Number of Wear Indications at Support	97	1	6	19	89	14	12	1	2
Average Change in Wear Depth (% Throughwall)	11%	6%	4%	19%	8%	8%	9%	20%	12%
Total Number of New Wear Indications at Support	22	0	0	2	6	2	1	1	1
Percent of New Wear Indications at Support	23%	0%	0%	10%	7%	14%	8%	100%	50%
Percent of Total Steam Generator Wear Indications	26.80%	0.28%	1.66%	5.25%	24.59%	3.87%	3.31%	0.28%	0.55%
Percent of Total Steam Generator New Wear Indications	28.21%	0.00%	0.00%	2.56%	7.69%	2.56%	1.28%	1.28%	1.28%

NOTE: Wear rates determined by this study were biased high by the exclusion of data from wear indications of below 20 percent.

Table V.J.4

STEAM GENERATOR WEAR STUDY
SG 22

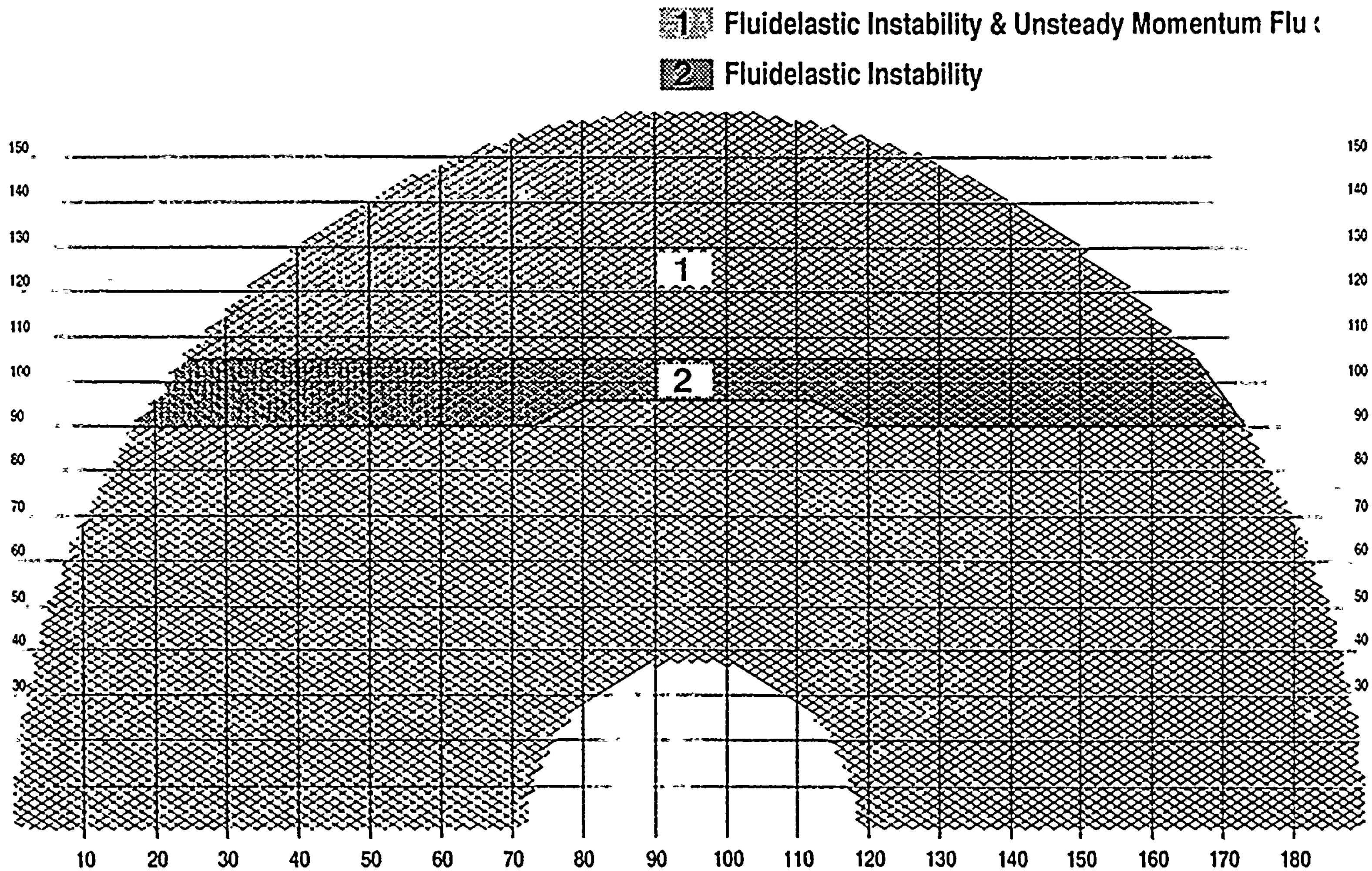
GENERATOR 21 WEAR CHANGE STUDY	ALL SUPTS.	01C SUPT.	02H SUPT.	03C SUPT.	04C SUPT.	05H SUPT.	07C SUPT.	07H SUPT.	08C SUPT.	
Total Number of Wear Indications at Support	389	2	2	3	4	1	1	9	77	
Average Change in Wear Depth (% Throughwall)	10%	14%	3%	4%	24%	6%	10%	14%	11%	
Total Number of New Wear Indications at Support	78	1	0	0	4	0	0	2	12	
Percent of New Wear Indications at Support	20%	50%	0.00%	0%	100%	0%	0%	22%	16%	
Percent of Total Steam Generator Wear Indications	100%	0.50%	0.50%	1.00%	1.00%	0.26%	0.26%	2.30%	20.00%	
Percent of Total Steam Generator New Wear Indications	100%	1.00%	0.00%	0.00%	5.00%	0.00%	0.00%	2.60%	15.00%	

GENERATOR 22 WEAR CHANGE STUDY	09H SUPT.	BW1 SUPT.	BW2 SUPT.	VS1 SUPT.	VS2 SUPT.	VS3 SUPT.	VS4 SUPT.	VS5 SUPT.	VS6 SUPT.
Total Number of Wear Indications at Support	92	129	5	5	5	31	10	11	1
Average Change in Wear Depth (% Throughwall)	18%	6%	13%	9%	6%	7%	10%	4%	16%
Total Number of New Wear Indications at Support	35	17	2	0	1	2	1	1	0
Percent of New Wear Indications at Support	38%	22%	40%	0%	20%	6%	10%	9%	0%
Percent of Total Steam Generator Wear Indications	24.00%	33.00%	1.30%	1.30%	1.30%	7.90%	2.60%	2.80%	0.26%
Percent of Total Steam Generator New Wear Indications	45.00%	22.00%	2.60%	0.00%	1.30%	2.60%	1.30%	1.30%	0.00%

NOTE: Wear rates determined by this study were biased high by the exclusion of data from wear indications of below 20 percent.

FIGURE V.K.1

Zones Susceptible to FIV Mechanisms with In-Plane Vibration



7993 ARC 4

FIGURE V.K.2

Zones Susceptible to FIV Mechanisms with Out-of-Plane Vibration

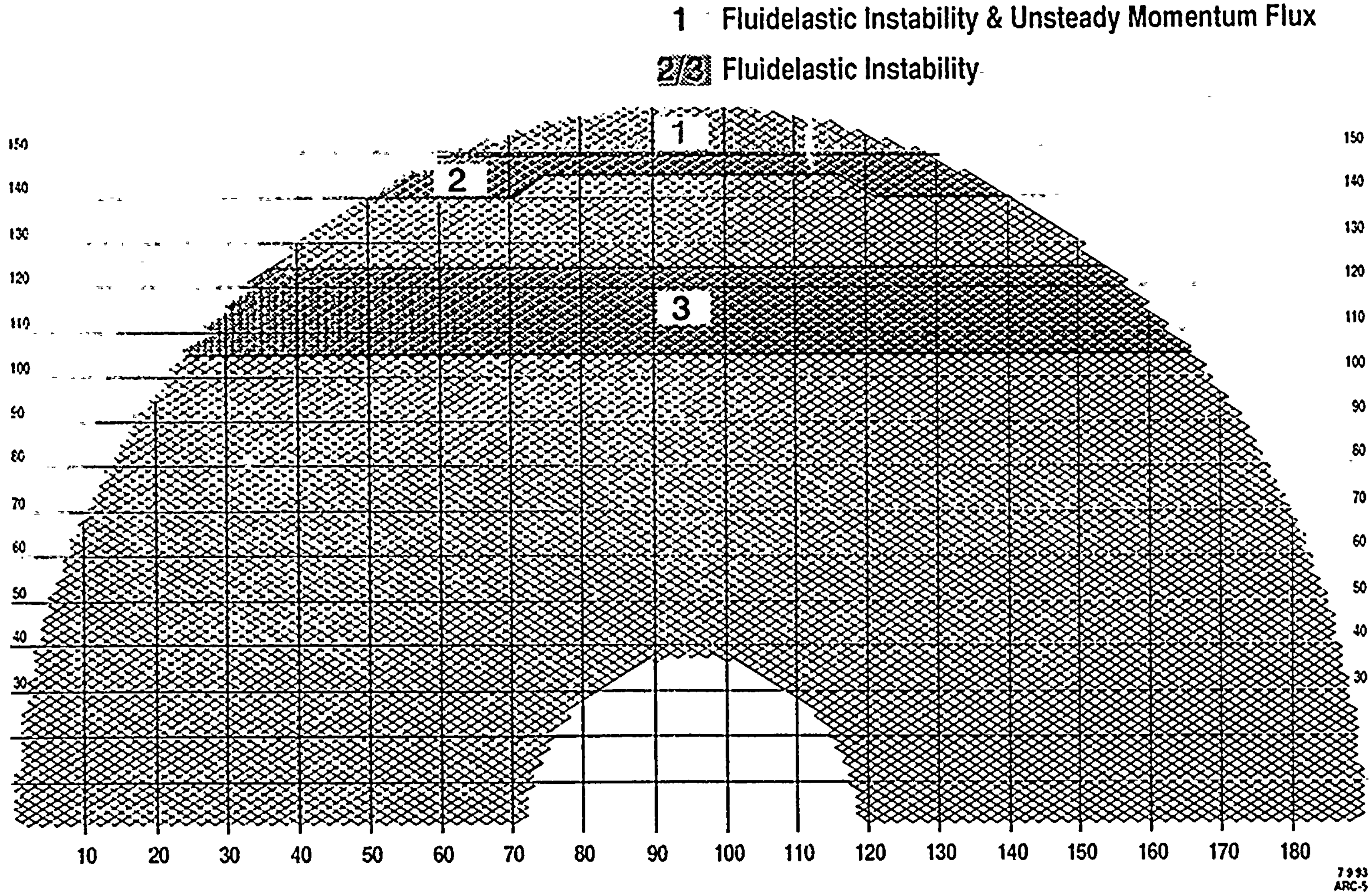


FIGURE V.L.1

Steam Generator 22 Tube Section Summary

Tube 103-156 (CE)

Support	Section	Observations
	17	Grooves, gauges and scratches were observed and the tube appears to be bowed with two mechanical damage in two locations. One was 12" long and the other 6", both were 1/4" wide. Cracks (avg. = 44.8% TW, max = 57.1% TW) were also present in the mechanical damaged areas.
08H	16	Triangular wear scars were found associated with the 08H support. Additionally, scratches were present which extends below the support location but not above. Deepest scratch is approximately 1 Mil.
	15	Long ridge deposit (14") about 0.25" wide. Tube section had a 0.030" bow. There were shallow scratches under the deposit.
07H	14	Tube appears to be slightly bowed with scratches above the support. Wear with deposits was found at the eggcrate location associated with the 07H support.
	13	Section of tube used for mechanical properties.
06H	12	Wear indications at 2 eggcrate support locations. Indications of support contact without wear at 2 contact locations. Descale and PT found no defects.
	11	Uniform deposits covering entire tube. There were no defects by PT following the swelling of the tube (8,000 psig).
05H	10	Wear indications at two support locations. Both wear scars covered with deposits. Around the bottom of the lower support locations was a deposit that had a rippled topography due to flow.
	9	Uniform deposit covering entire tube. There were some tube pull scratches.
04H	8	General tube deposits were uniform with some tube pull scratches. There was evidence of support contact. There was wear indications on deposits, no bear metal showing.
	7	Non-uniform deposits over entire tube surface. These deposits had a mottled appearance due to flow.
03H	6	Non-uniform deposit with a motted appearance due to flow. Deposit buildup at the edges of eggcrate contact locations. Deposit near tube surface was white/light orange in color. Some shallow scratches under general tube deposit.
	5	Uniform tube deposits with mottled appearance due to flow.
	4	Non-uniform tube deposits with mottled appearance due to flow. White deposit next to the tube surface.
02H	3	Indications of support contact with the tube. White deposits near the tube surface. No evidence of wear.
01H	2	Tube to plate contact covers about 90° of tube surface and is 0.75" wide. Some deposits within plate crevice thickness and the deposits transfered the machining marks from the drilled hole. The deposits near the tube were white. Near the top of the plate were short circumferential marks.
Tube Sheet	1	No defects found at the top of the tubesheet.

Note: There was evidence of tube scratches under the general deposits on most tube sections.

7993 MATRIX48

FIGURE V.L.2

Steam Generator 22 Tube Section Summary		
Tube 105-156 (CE)		
	16	Axial cracking with deposits at the top of the tube and extends to 7" below the whip cut. Crack has IGSCC with IGA located around the crack area. Avg. crack depth = 77% TW.
08H	15	Axial scratches with surface deposits approx. 3 Mils wide and 1 Mil deep and wear marks associated with the 08H support.
	14	This tube was descaled and sectioned for mechanical properties.
07H	13	Wear associated with 07H support.
	12	Uniform deposits covering the tube with minor tube pull scratches. Tube section pressurized to 8,000 psig, and descaled, no defects found.
06H	11	Uniform deposits generally covering the tube surface with exception of three support contact locations. Wear was on two contact points. The edges of all contact points had a thicker deposit buildup. There was a scratch under the deposit at one of the contact locations. The tube burst at 10,180 psig, ductile failure. Following descaling, IGA found not to be associated with the burst.
	10	Uniform general deposits covering the tube with minor tube pull scrapes. The tube section was pressurized to 8,000 psig, then descaled, no defects found.
05H	9	Tube covered with a non-uniform deposit which had a rippled topography due to flow. Evidence of three support contact locations. Two contact points had wear scars (no bare metal). There was a slight ridge deposit approx. 0.75" long and 3/8" wide.
	8	Uniform general deposits covering tube with minor tube pull scrapes.
04H	7	Non-uniform deposits with some motting and minor tube pull scrapes. There were three contact points that were the result of burnishing of tube deposits under the support. There was no bare metal.
	6	Non-uniform general deposits covering tube which had a mottled appearance due to flow. There were some minor tube pull scrapes.
03H	5	Non-uniform tube deposits with exception of two support contact locations. Both of these contact points had a thick scale formation. This scale had areas which were reddish in color.
	4	Non-uniform general deposits covering tube which had a mottled appearance due to flow. There were some minor tube pull scrapes.
02H	3	Non-uniform deposits on tube surface. Large area where deposit spalled from the tube. Some scratches on tube under deposit. Tube was bowed approx. 3/8" (could have been bent during tube pull). There was one support contact location. Deposits at the contact point were white near the tube surface.
01H	2	Evidence of flow distribution plate contact location. Deposits in tube/plate crevice are thick. At some points the machining marks from drilled hole had been transferred to deposit.
Tube Sheet	1	Tube section severely damaged during tube pull (TIG and deep scores). Band of bare metal around tube 2.75" above tubesheet and 1/8" wide (possibly a result of the TIG).

7-9-93
MATRIX4A

FIGURE V.L.3

Steam Generator 22 Tube Section Summary

Tube 117-144 (CE)

	16	Axial crack from the top of the tube (at whip cut) extends approx. 4" down with a deposit ridge covering the crack surface. Both IGA and IGSCC are associated with the crack. (avg. IGSCC = 70.2% TW, max IGSCC = 98.2% TW).
08H	15	Uniform deposit covering tube. Four eggcrate contact locations visible. At two supports tube/support movement evident, deposits were burnished. Deposit buildup heavier near the edges of the point of contact. White deposits near surface of tube.
	14	Uniform deposits. Minor tube pull scratches. Metallic copper-looking deposits exposed at tube pull scraps.
07H	13	Uniform deposits with the exception of three support contact locations. Wear was evident at one point exposing scratches under the deposit. Under the deposit the tube surface was copper color. At the bottom of two contact locations were rippled deposits from flow. At 8,000 psig three short leaking cracks developed at the support wear. Following descaling IGA was founded in the bottom of a scratch.
	12	This tube was descale and sectioned for mechanical properties.
06H	11	Two support contact locations noted. One contact point was 2" long with the upper 0.5" showing bare metal due to wear. There were heavier deposits on the edges of the contact location and flow ripples in the deposits at the bottom of the contact point.
	10	Uniform deposits covering entire tube surface with minor tube pull scrapes.
05H	9	Three support locations observed. One of these was evident due only to the presence of flow ripples in the deposits. The other two were contact points with a heavier deposit near the edges. At the bottom of one point was a small (0.25") wear mark, no bare metal showing.
	8	Uniform deposits covering tube with some tube pull scratches.
04H	7	Uniform tube deposit with the exception of four support contact locations. There was a heavier deposit buildup at edges of contact location. Evidence of wear at two points. At the interface of wear and deposit at one point was roughening.
	6	Non-uniform deposit covering tube surface. Surface was motted due to flow. General deposit seemed heavier than general deposits from upper tubes.
03H	5	Non-uniform deposit covering the general tube surface. There were three support contact locations. At one contact point there was bare metal and no wear.
	4	Non-uniform deposit covers tube. Deposit mottled and ripples present due to flow.
02H	3	Non-uniform general deposits with two support contact locations. The tube surface at the contact points showed the belt polishing marks. The deposits near the tube surface were white and light orange in color.
01H	2	Non-uniform deposits. There was a 1" wide contact location at the elevation of the flow distribution plate. In some areas the deposits were thick.
Tube Sheet	1	Most of the section was damaged due to tube pull (TIG and very heavy scrape). There was no evidence of corrosion damage in the 3.5" of tubing above the tubesheet.

Note: There was evidence of tube scratches under the general deposits on most tube sections.

7993
MATRIX3A

FIGURE V.L.4

Steam Generator 22 Tube Section Summary		
Tube 127-140 (CE)		
	16	Uniform deposits covering the tube surface. There were no ridge-like deposits. Some light tube pull scrapes.
08H	15	Axial crack (avg. = 56% TW, max = 89% TW) with both IGA and IGSCC located at the 08H support and wear marks associated with the support.
	14	Uniform deposits covering the tube surface. There were no ridge-like deposits. Some light tube pull scrapes.
07H	13	Axial crack (avg. = 40% TW) with both IGA and IGSCC located at the 07H support and wear marks associated with the support.
	12	This tube was descaled and sectioned for mechanical properties.
06H	11	Wear marks associated with the 06H support.
	10	Uniform deposits over entire tube with minor tube pull scratches.
05H	9	Long wear marks associated with the 05H support.
	8	Uniform deposits over entire tube with minor tube pull scrapes.
04H	7	Non-uniform general tube deposits. There was evidence of three support contact locations. At the top of two contact points the under support deposits were burnished due to wear, no metal exposed. The third point had a 1/8" wear spot at the bottom of the contact point, bare metal showing.
	6	Non-uniform deposits covering entire tube with minor tube pull scrapes.
03H	5	Non-uniform general tube deposits. Evidence of four support contact locations. Two contact points, at the same elevation, had large deposits that connected them which spalled off of the tube (60° wide, 1" long). There were scratches under the deposits at one support location. The deposits near the tube surface were both white and light orange in color.
	4	Non-uniform deposits covering entire tube with minor tube pull scrapes. White deposits near tube surface.
02H	3	Evidence of four support contact locations. Two contact points 180° apart had collection of black whisker-like fibers (0.5" long). The deposits were thicker at the edges of the contact points and had a rough appearance.
01H	2	The contact point between the flow distribution plate and tube was 1" long. Some of the deposits had evidence of the machining marks transferred from the drilled plate. The deposits near the tube surface were white and light orange in color.
Tube Sheet	1	Tube damaged due to tube pull, no corrosion damage seen.

Note: There was evidence of tube scratches under the general deposits on most tube sections.

7-9-93
MATRIX3B

FIGURE V.L.5

Steam Generator 22 Tube Section Summary

Tube 117-40 (B&W)

Support	Section	Description
09H	17	Multiple partial length axial scratches w/associated consistent cracking (avg. = 27% TW, max. = 61%TW) and a mix of both IGA and IGSCC. Axial ridge of deposit beginning at the top of the section and tapering tapering off at the top were also found approx. 2.5" from the top to 4.5" from the top. (Approximate location of the 09H support)
	16	Three axial scratches w/intermittent cracking (approx. 10 - 15% deep) and light IGA.
08H	15	Three axial scratches w/intermittent cracking (approx. 10 - 15% deep) with light IGA and wear marks associated with the 08H support.
	14	Multiple axial scratches w/intermittent cracking (approx. 5% deep) and light IGA.
07H	13	Multiple axial scratches w/intermittent cracking (approx. 5% deep) and light IGA.
	12	Multiple axial scratches w/loose powder-like deposit covering, and also older, extremely adherent deposit.
06H	11	Multiple axial scratches w/several minor wear marks associated with the 06H support.
	10	Multiple axial scratches.
05H	9	Multiple axial scratches.
	8	Multiple axial scratches with one short crack.
04H	7	Axial scratches.
	6	Axial scratches.
03H	5	Axial scratches.
	4	Axial scratches.
02H	3	Axial scratches with two occational minor cracking and IGA.
01H	2	Axial scratches.
Tube Sheet	1	Not analyzed.

NOTE: All scratches are shallow (< 1.0 Mil. deep)

7-9-93 MATRIX1A

FIGURE V.L.6

Steam Generator 22 Tube Section Summary		
Tube 116-41 (B&W)		
09H	19	Two partial length axial scratches w/associated intermittent cracking (12% deep) and some IGA. "Tear drop" shaped wear mark approx. 16 Mils deep (max. = 25% TW) associated with scallop bar contact.
	18	One full length axial scratch w/associated intermittent cracking (5% deep) and minor IGA.
08H	17	Two axial scratches w/associated cracking (5% deep) and some IGA. Light wear associated with 08H support.
	16	Axial scratches w/minor crack and IGA (more prominent near top of tube section).
07H	15	Axial scratches and minor IGA at eggcrate, generally associated with wear marks.
	14	One full length scratch, "tear drop" shaped wear pattern in circumferential band.
06H	13	Two full length axial scratches w/very minor crack just outside the scratch.
	12	Axial scratches
05H	11	Axial scratches w/minor IGA. Three minor wear marks.
	10	Axial scratches.
04H	9	Axial scratches.
	8	Axial scratches.
03H	7	Axial scratch and rough surface over bottom half of tube section
	6	Axial scratches.
02H	5	Axial scratch and severe scrape marks. Tube appears to be bowed and has wear marks and a rippled surface.
	4	Minor wear marks with axial scratches.
01H	3	Axial scratches.
	2	Axial scratches.
Tube Sheet	1	Not analyzed

NOTE: All scratches are shallow (< 1.0 Mil. deep)

7/9/93
MATRIX18

FIGURE V.L.7

Steam Generator 22 Tube Section Summary

Tube 29-24 (B&W)

03H

7993
MATRIX2A

	4	No defects noted
02H	3	No defects noted
01H	2	Short axial indication w/some IGA
Tube Sheet	1	Not analyzed

FIGURE V.L.8

Steam Generator 22 Tube Section Summary

Tube 22-13 (B&W)

03H

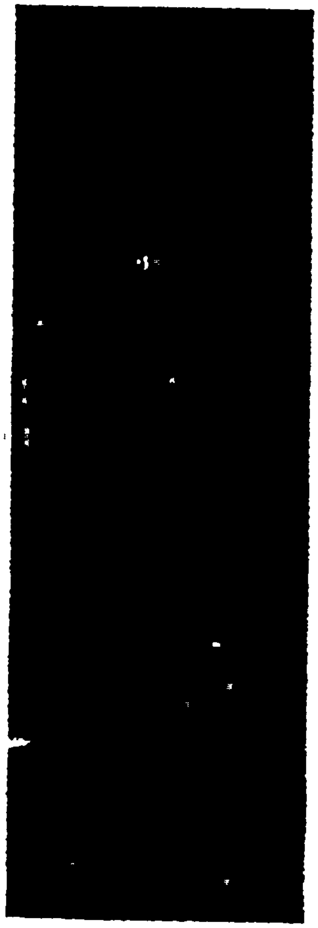
02H

01H

Location	Section	Finding
	5	No defects noted
	4	No defects noted
02H	3	No defects noted
01H	2	Short axial IGA cracks
Tube Sheet	1	Not analyzed

6 21,93
MATRIX28

V.L
Figure S. Tube R116C41 09H location showing wear scar resulting from contact with the scallop bar. 7.5x.

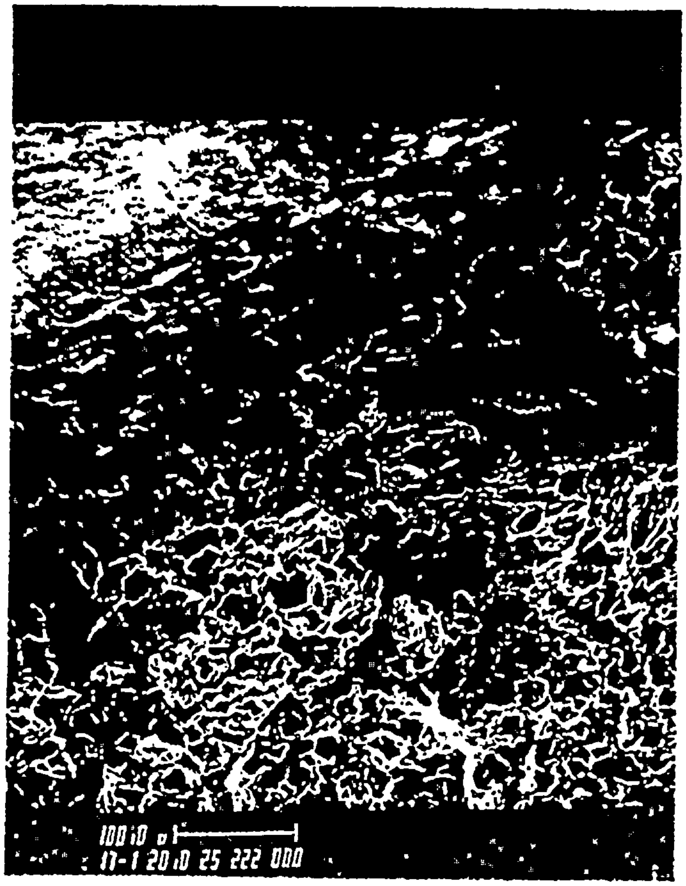


V.L
Figure T. Tube R103C156 06H support location showing wear indications.

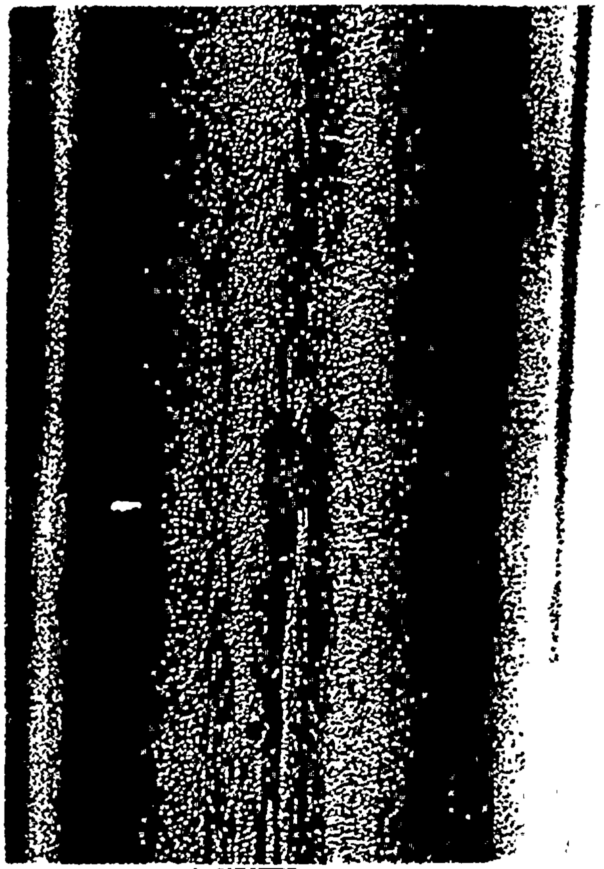
V.L
Figure Q. SEM photomicrograph of tube R127C140, 07H burst surface showing surface groove and IGSCC progressing from the surface. 200x.

V.L
Figure R. As-received sample of ruptured tube R117C144 after bending to open up surface IGA.

V.L
Figure O. SEM photomicrograph of tube R103C156 surface in area of IGA. 200x.

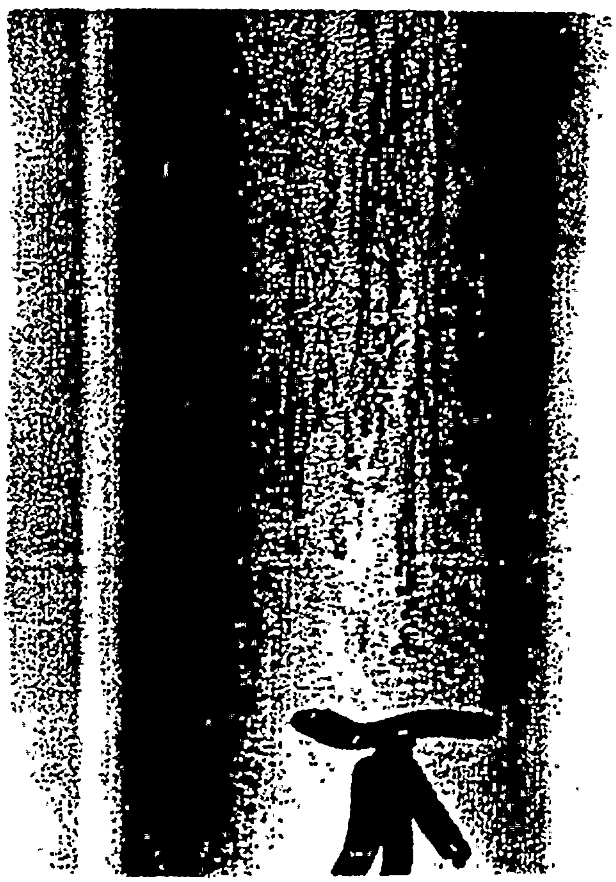


V.L
Figure P. SEM photomicrograph of tube R127C140, 07H burst surface showing surface grooves and associated IGA / IGSCC. 200x.



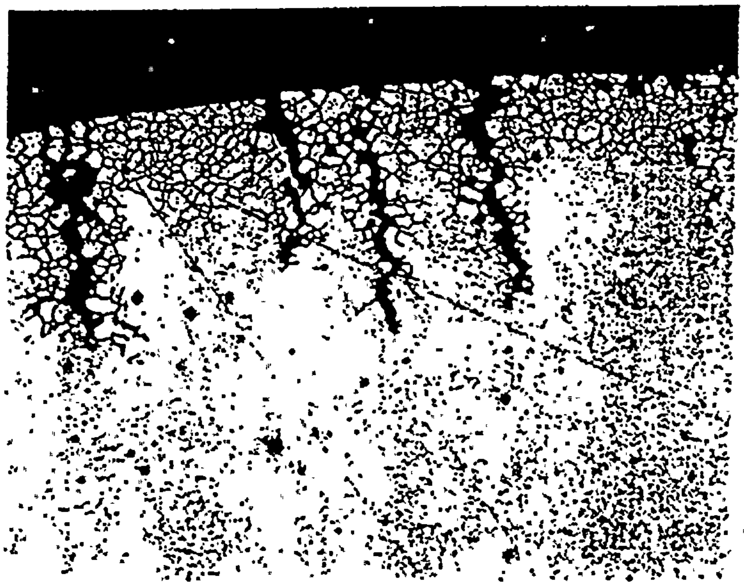
V.L

Figure M. Photomacrograph of tube R103C156 freespan area showing surface damage and associated IGA / IGSCC. Area is 1/4 - inch wide and was associated with ridge deposits.

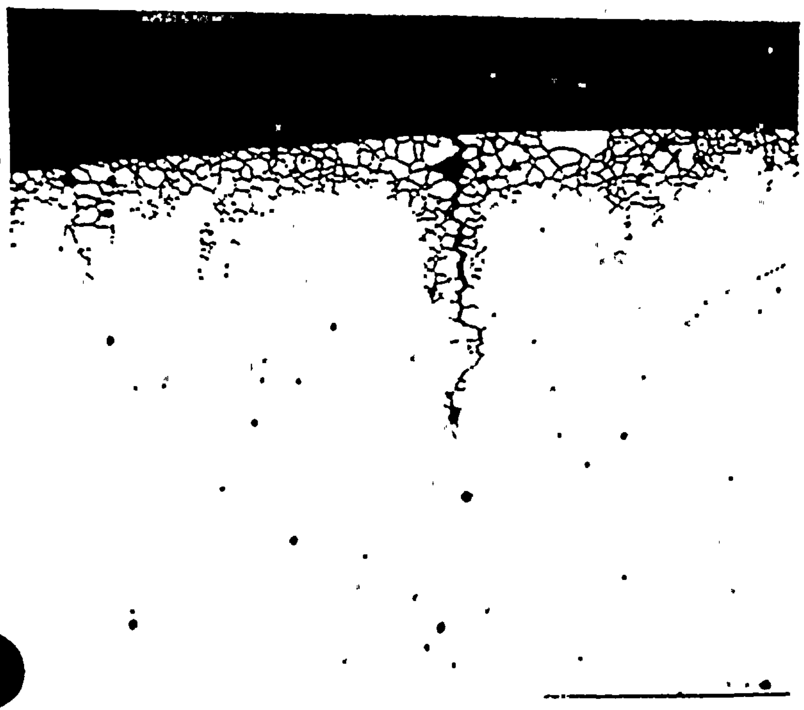


V.L

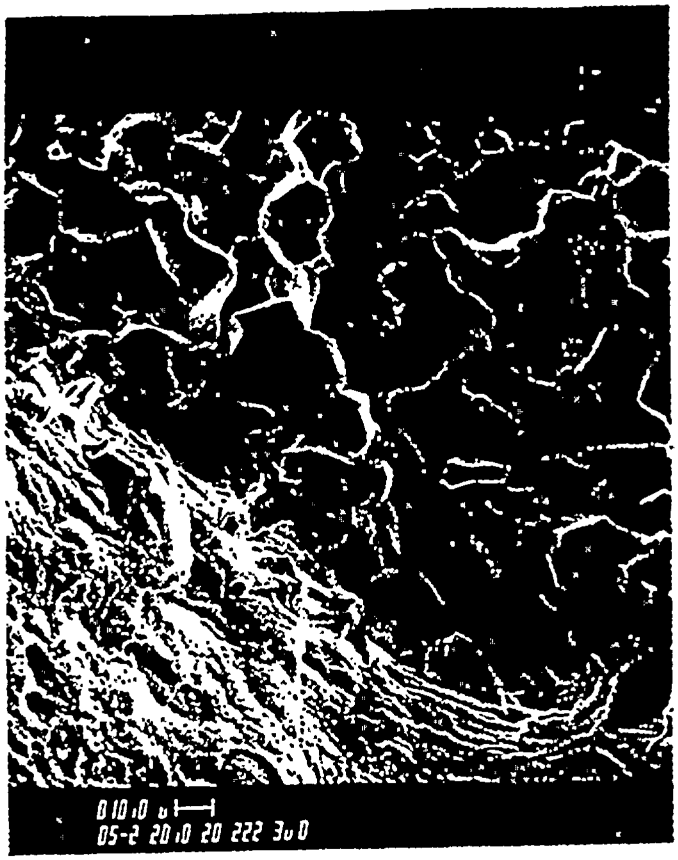
Figure N. Photomacrograph of tube R103C156 freespan area showing surface damage and associated IGA / IGSCC. Arrow notes the end of damaged area and associated IGA.



V.L
Figure K. Cross-sectional photomicrograph of tube R105C156 showing IGA and IGSCC.



V.L.
Figure L. Cross-sectional photomicrograph of tube R105C156 showing IGA and IGSCC.

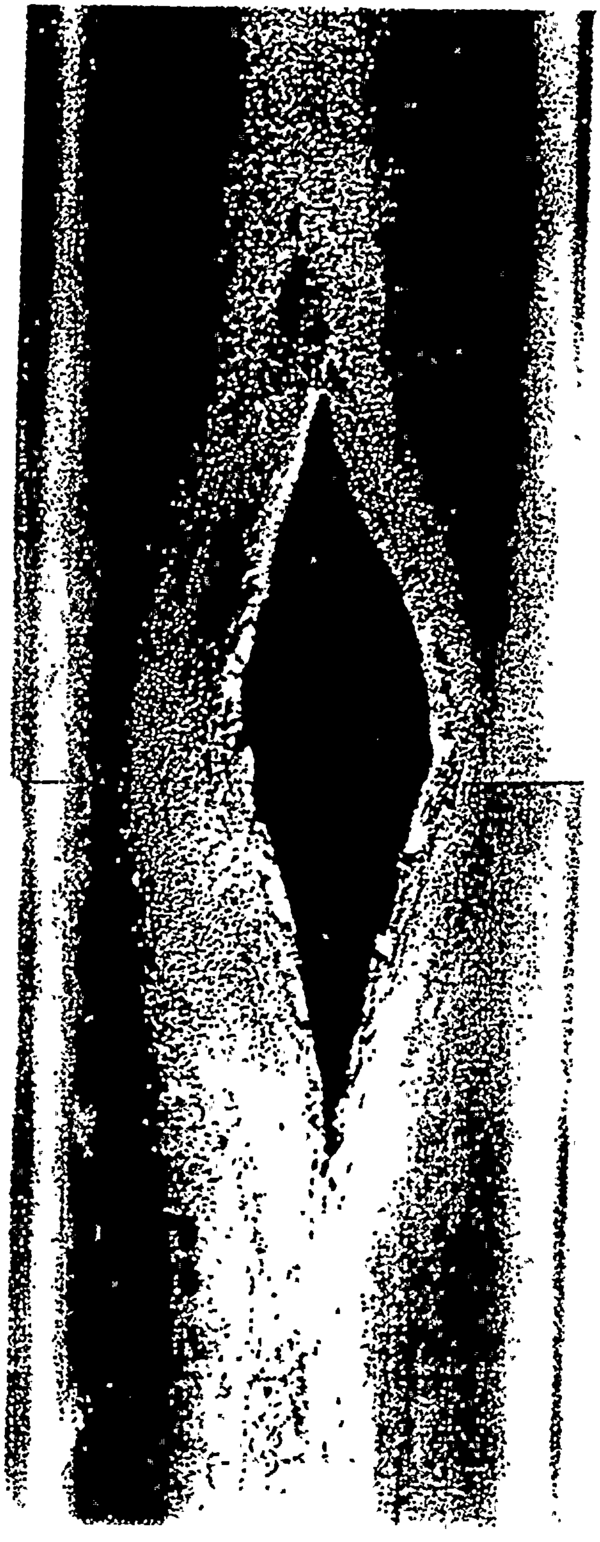


V.L

Figure I. Scanning electron micrograph of R105C156 fracture surface showing "rock candy" appearance of IGSCC. Lower left hand portion of photo is the area of ductile shear from the burst test. 500x.

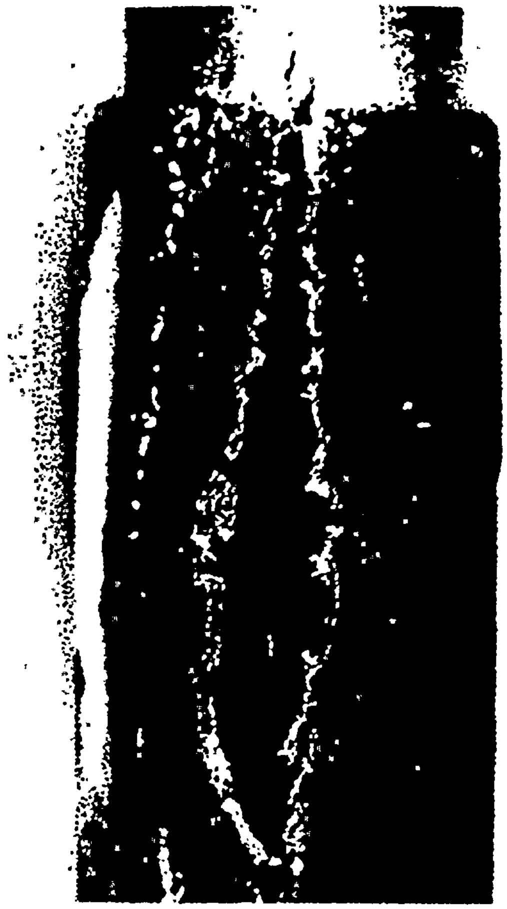
V.L

Figure J. Scanning electron micrograph of tube R117C144 burst surface confirming IGSCC as the mode of cracking.



V.L

Figure H. Photomacrograph of Tube R103C156 burst surface. Surface is descaled for examination purposes. Burst opening length is 0.325 inches. Top end of burst fracture is 100% ductile tearing, bottom end of burst fracture is combination IGSCC and ductile tearing.



V.L
Figure F. Photomacrograph of Tube R105C156 burst surface. Burst pressure was 3200 psig. Burst length was 1.38 inches in length.

V.L
Figure G. Photomacrograph of Tube R127C140 burst surface for axial crack defect located at the 08H support location. Burst length was 1.0 inches long. Burst pressure was 6119 psig.

V.L
Figure D. As-received photo of tube R105C156, section 16 showing freespan area of bridged deposit formation.

V.L
Figure E. Tube R105C156, section 16 showing axial cracks extending from the burst area and groove marks.

TABLE V.N.1

HIDEOUT RETURN CHEMISTRY DATA COMPARISONS

PARAMETER	UNIT 1	UNIT 2	UNIT 3	NOTES
SG 1 CHLORIDE	130	65	11	AVERAGE OF ALL PEAK ppb VALUES
SG 1 SULFATE	249	209	231	"
SG 1 SODIUM	232	172	229	"
SG 2 CHLORIDE	91	59	19	"
SG 2 SULFATE	254	228	237	"
SG 2 SODIUM	213	270	231	"
SG 1 RATIO	1.6	2.1	2.7	The average Na/Cl+SO4 ratio of each
SG 2 RATIO	2.0	2.6	3.1	individual shutdown.
SG 1 MR	2.8	2.9	106	The average Na/Cl ratio of each
SG 2 MR	8.1	19.2	89	individual shutdown.
SG 1/2 CHLORIDE	0.9	1.1	0.7	Average SG #1 DIVIDED BY SG #2 data
SG 1/2 SULFATE	1.2	0.9	1.1	from each individual shutdown for
SG 1/2 SODIUM	0.9	0.6	1.0	chloride, sulfate and sodium.

Above data includes: Unit One: 19 shutdowns July 1987 - February 1993
Unit Two: 19 shutdowns July 1987 - March 1993
Unit Three: 15 shutdowns August 1988 - February 1993

1991 - 1993 HIDEOUT RETURN DATA

PARAMETER	UNIT 1	UNIT 2	UNIT 3
CHLORIDE, average grams	9	2	3
SULFATE, average grams	53	84	37
SODIUM, average grams	42	97	43
LEAD, average grams	2	19	< 1
Na/Cl Ratio, average	7	75	22
MULTEQ, predicted pH *	10.20	10.23	10.35

* The above MULTEQ predicted pHs compare prompt hideout return data using the precipitates removed option. If cumulative data is used, and precipitates are not removed, the predicted pH is reduced in some cases to 8.6.

Table V.O.1

Hot Leg Side						
Column	Row	Above support	Expected height (inch)	Actual Height (inch)	Act-Exp Δ (inch)	Off-Center Δ (inch)
27	20	07H	10.89	10.43	-0.46	
27	64	07H	50.81	48.53	-2.28	+0.42
27	108	08H	45.72	42.47	-3.25	
54	19	07H	9.99	9.67	-0.32	
54	81	08H	21.23	20.36	-0.87	-0.025
54	143	09H	32.47	31.00	-1.47	
81	30	07H	19.96	20.15	+0.19	
81	88	08H	27.58	26.55	-1.03	+0.593
81	156	09H	44.26	43.10	-1.16	
108	31	07H	20.87	21.62	+0.75	
108	89	08H	28.49	28.16	-0.33	+0.913
108	155	09H	43.36	43.76	+0.40	
135	20	07H	10.89	10.95	+0.06	
135	82	08H	22.14	22.00	-0.14	-0.415
135	144	09H	33.38	32.22	-1.16	
162	19	07H	9.99	9.85	-0.14	
162	65	08H	6.71	7.00	+0.29	-0.513
162	111	08H	48.44	47.90	-0. 54	

Table V.O.2

Cold Leg Side						
Column	Row	Above support	Expected height (inch)	Actual Height (inch)	Act-Exp Δ (inch)	Off-Center Δ (inch)
27	20	07C	10.89	10.45	-0.44	
27	64	07C	50.81	51.10	+0.29	-1.175
27	108	08C	45.72	44.40	-1.32	
54	19	07C	9.99	10.02	+0.03	
54	81	08C	21.23	21.18	-0.05	-0.36
54	143	09C	32.47	31.62	-0.85	
81	30	07C	19.96	20.18	+0.22	
81	88	08C	27.58	27.72	+0.14	-0.704
81	156	09C	44.26	42.79	-1.47	
108	31	07C	20.87	20.66	-0.21	
108	89	08C	28.49	27.90	-0.59	-0.905
108	155	09C	43.36	40.41	-2.95	
135	20	07C	10.89	10.48	-0.41	
135	82	08C	22.14	21.00	-1.14	-0.415
135	144	09C	33.38	32.00	-1.38	
162	19	07C	9.99	9.73	-0.26	
162	65	07C	51.71	50.3	-1.41	-0.513
162	111	08C	48.44	47.34	-1.10	

FIGURE V.P.1

Postulated Bridging Above Batwing

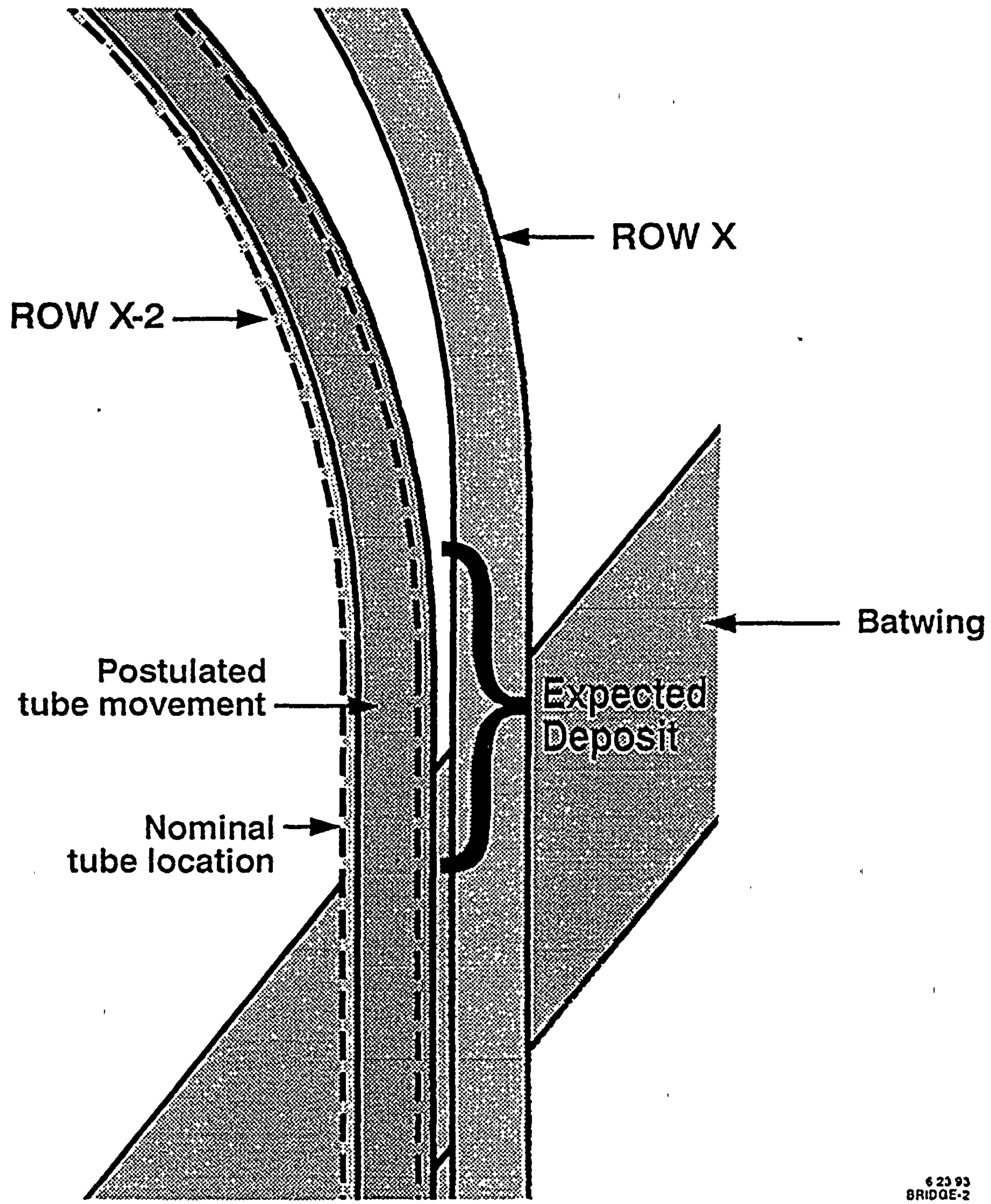
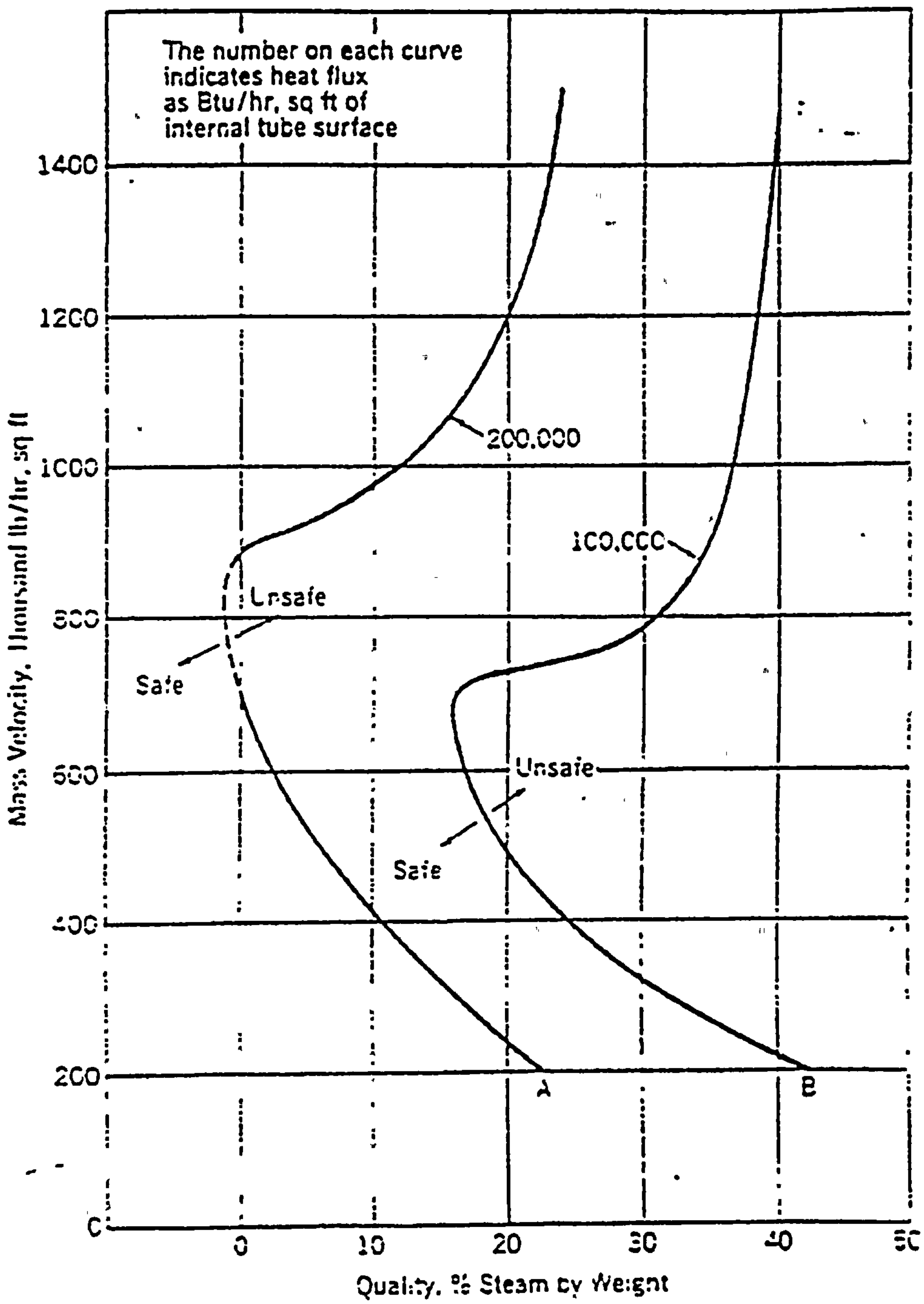


FIGURE V.P.2

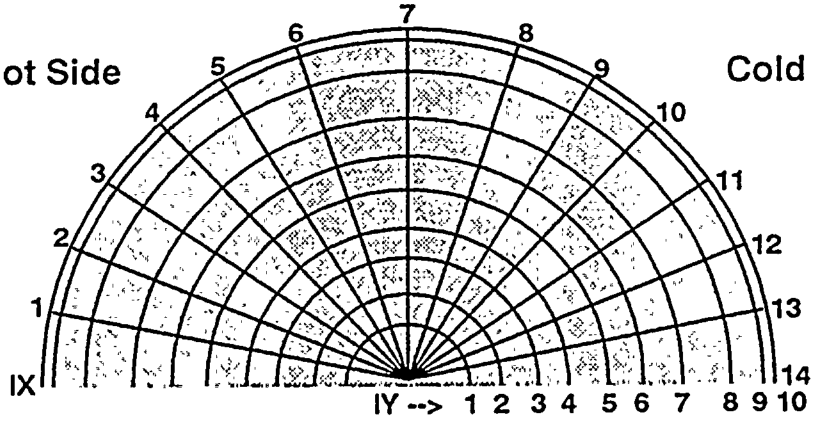
B&W Transition Correlation



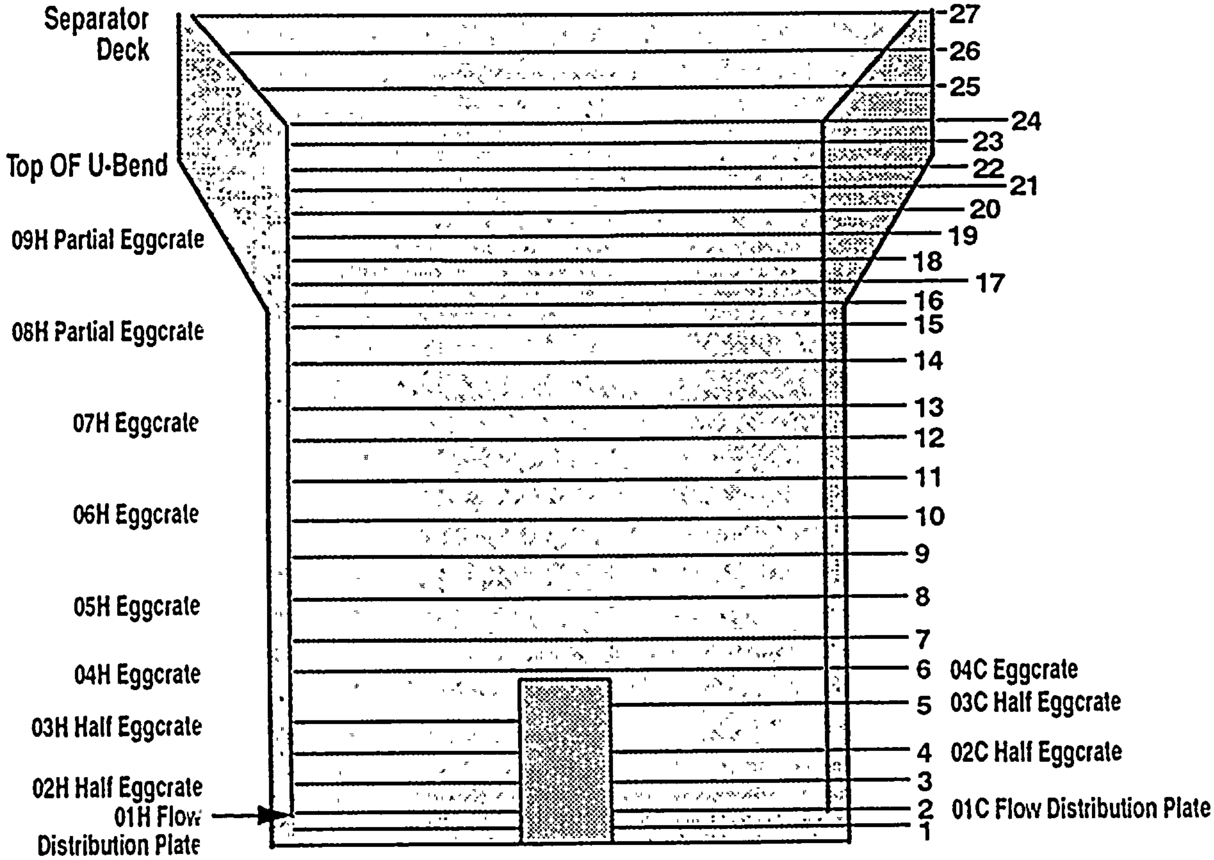
6 23 93
B&W-1

FIGURE V.P.3

ATHOS II Model
Palo Verde Steam Generator



Horizontal Nodalization

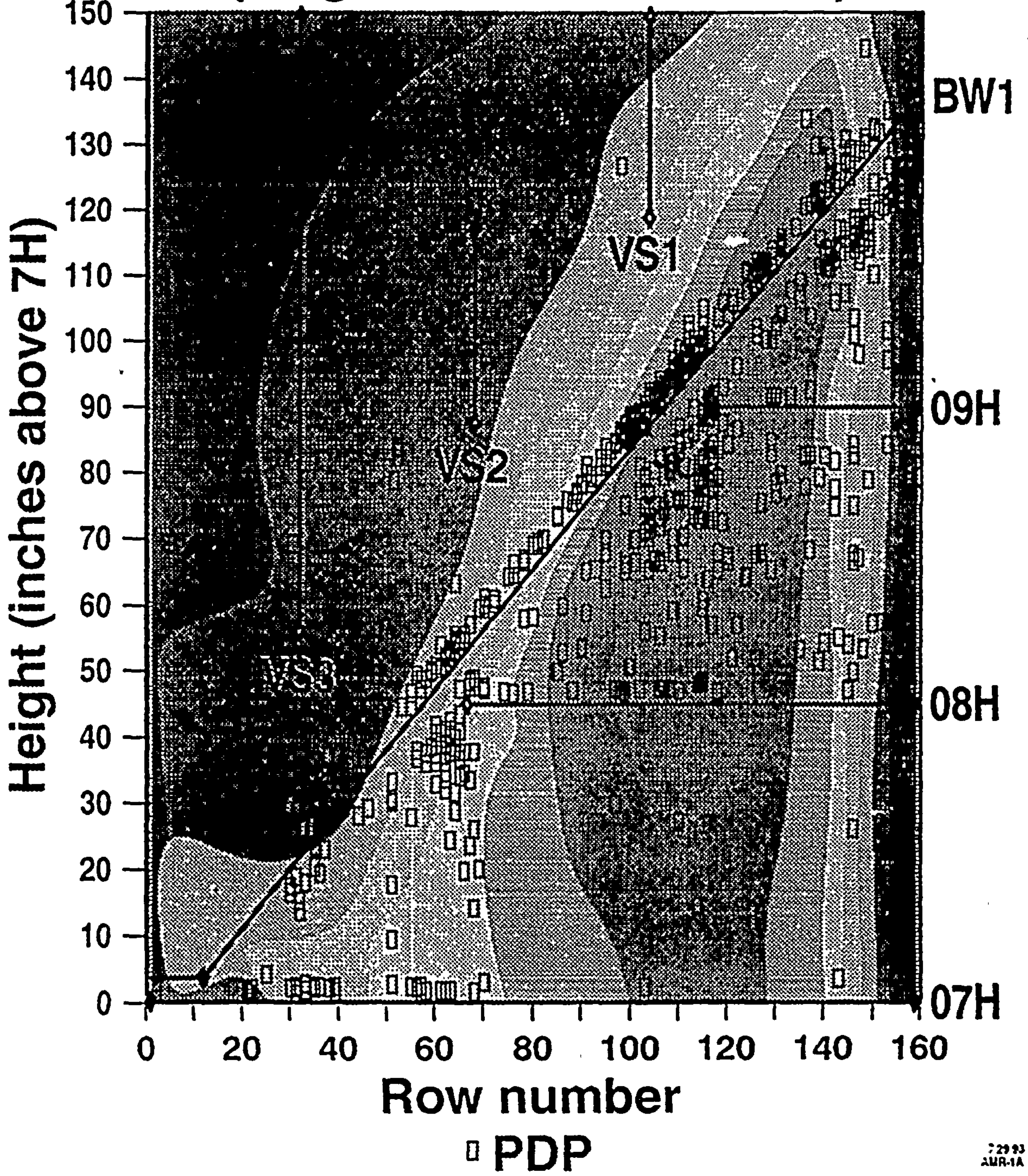


Vertical Nodalization

8 93 ATHOS-2

FIGURE V.P.15 Based on 7/16 Data (Final)

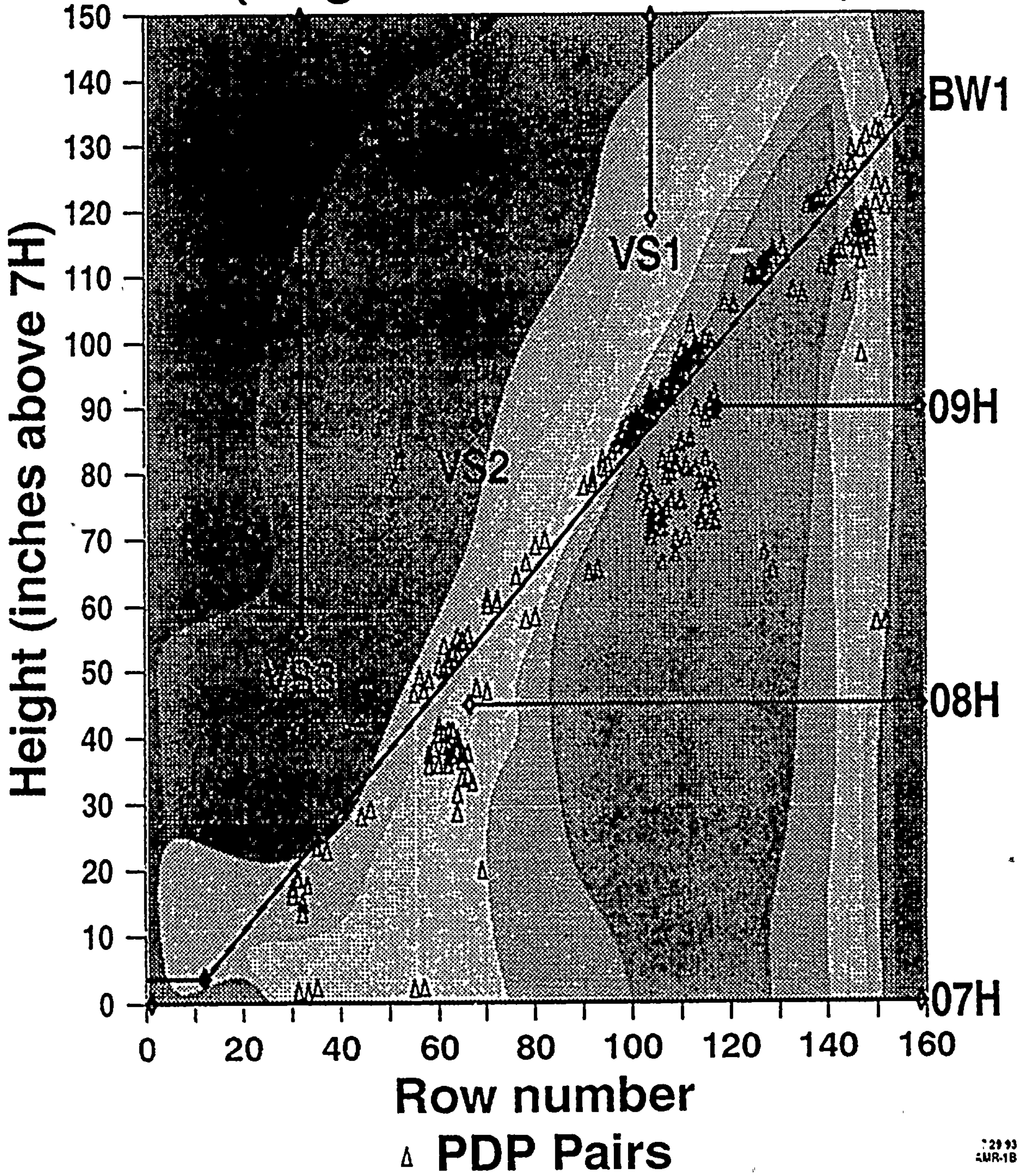
SG21 Deposits
(Height above 7H vs. Row)



7 29 93
AUR-1A

FIGURE V.P.16 Based On 7/16 Data (Final)

SG21 PDP "Pairs"
(Height above 7H vs. Row)



7 29 93
AMR-1B

FIGURE V.P.17

7/16 Data (Final)

Steam Generator 21

Aligned Deposit "Pairs"

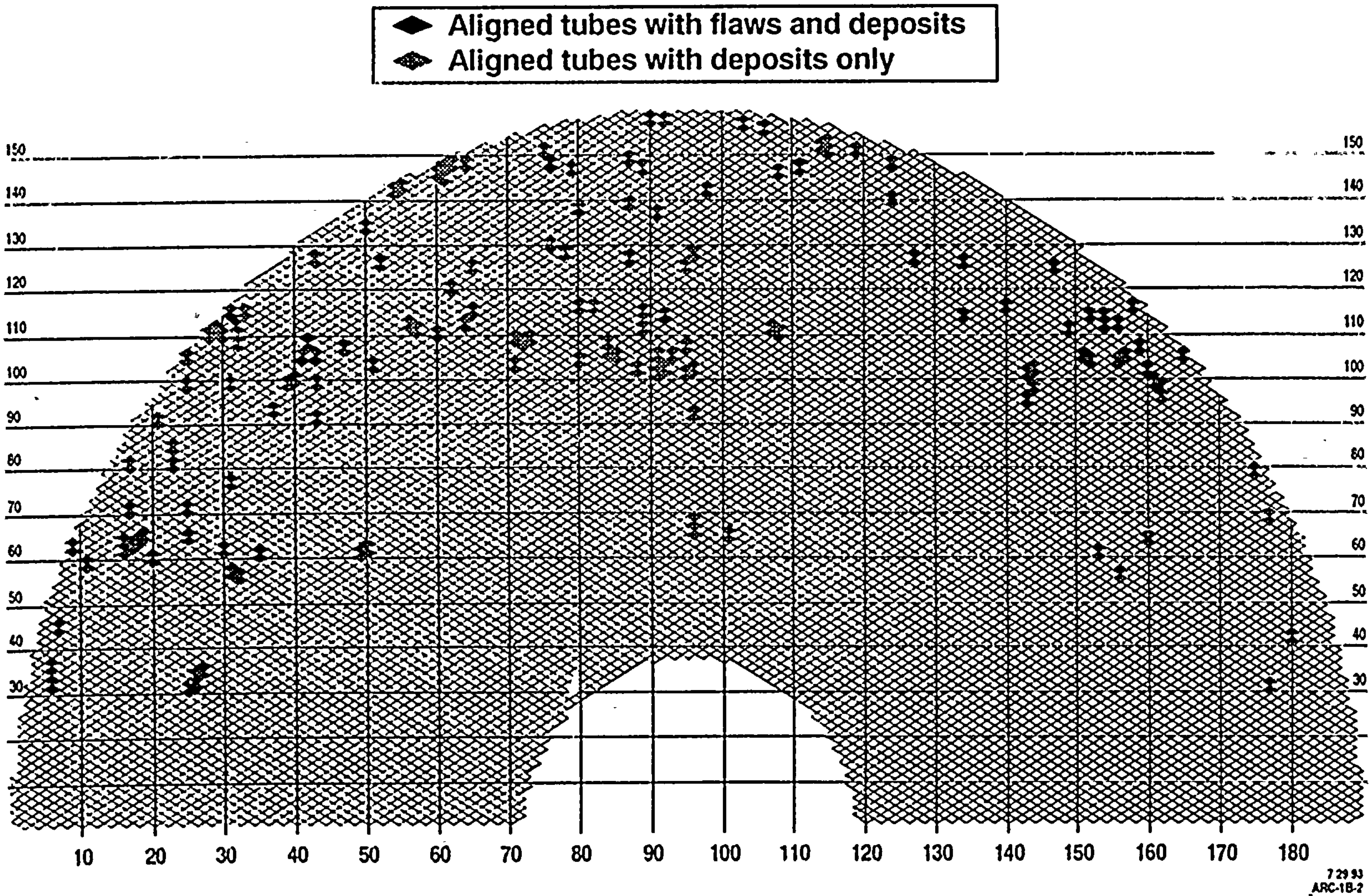
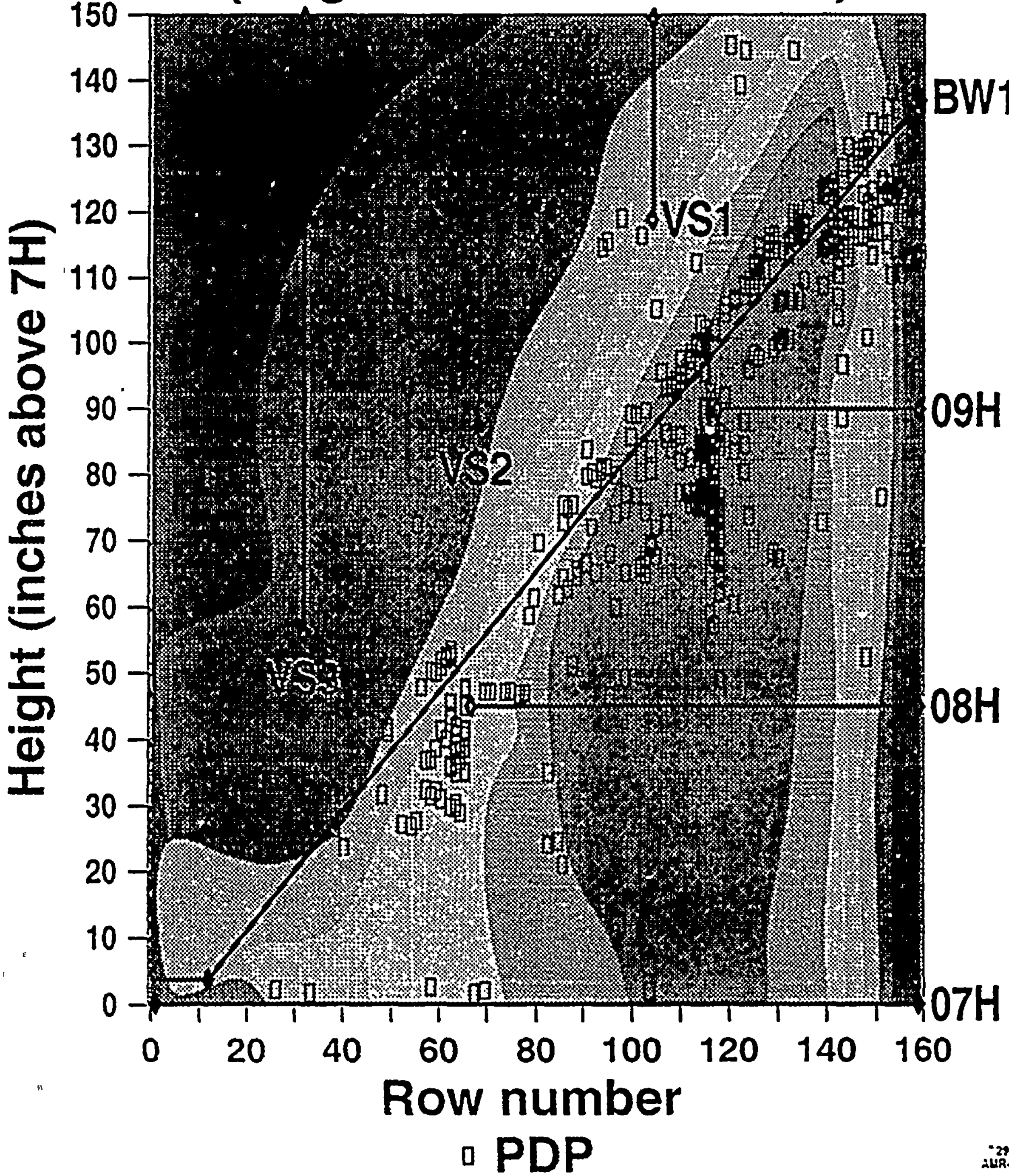


FIGURE V.P.18 Based on 7/16 Data (Final)

SG22 Deposits

(Height above 7H vs. Row)



7 29 93
AMR-1C

FIGURE V.P.19 Based on 7/16 Data (Final)

SG22 PDP "Pairs"
(Height above 7H vs. Row)

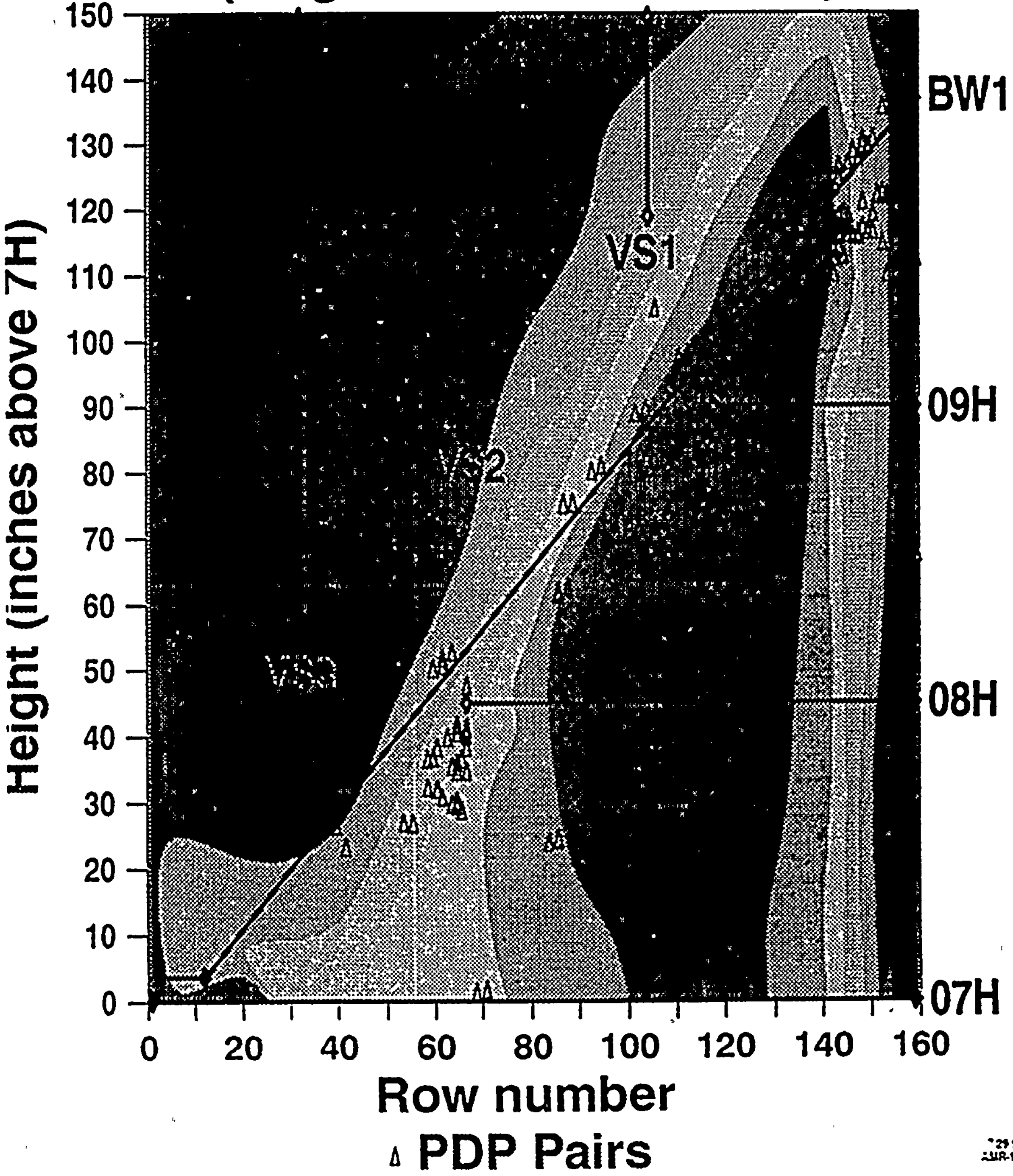
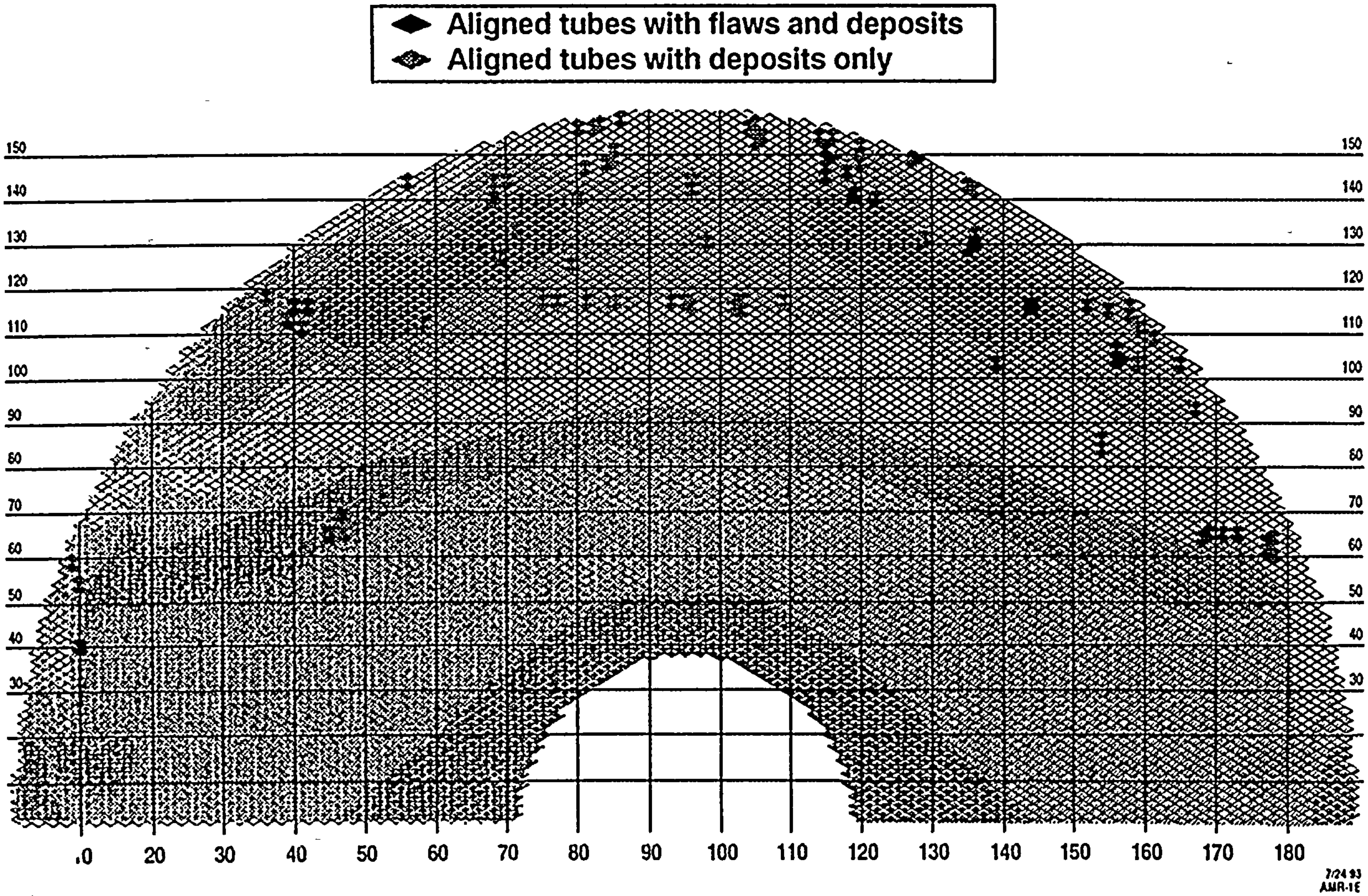


FIGURE V.P.20

7/16 Data (Final)

Steam Generator 22
Aligned Deposit "Pairs"



VI. ROOT CAUSE OF FAILURE DETERMINATION

Despite all troubleshooting efforts, the exact failure conditions experienced on March 14, 1993, could not be determined. After considerable evaluation, the Root Cause of Failure Investigation Team determined the failure mechanism leading to the SGTR event was due to IGA/IGSCC. The conditions that were established in Unit 2 steam generators can be attributed to the combined affect of several factors. Figure IV.B.c provides a summary of the contributing factors and possible causes based on key evidence. Each factor is discussed in the section along with possible causes.

The investigation concluded that the contributing factors of the tube rupture in the PVNGS steam generator were caustic-sulfate environment, crevice formation, contaminant concentration in crevices, flow induced vibration, residual stresses, less than optimal material by today's standards and eddy current testing. Other OD initiated axial defects were recorded at both supports and freespan elevations. The damage mechanism for these tubes was similar to that of the ruptured tube (see Figure IV.B.d).

A. CAUSTIC-SULFATE ENVIRONMENT

Secondary water chemistry evaluations and pulled tube laboratory analysis indicated the presence of a caustic environment for PVNGS steam generator crevices. This evidence is supported historically by the presence of OD initiated cracks during both U2R3 and U2R4 at support locations, hideout return data since January 1991, which indicates crevice pH ranges from 8.6 - 10.7 and sodium to chloride molar ratios averaging 75:1, and on-line steam generator blowdown molar ratios ranging from 2 to 5 typically.

The review of secondary operating chemistry indicates there has been a potentially aggressive environment in the Unit 2 SG's throughout their operating life. Although bulk water (hot leg blowdown) impurity levels have remained well within EPRI and CENPD-28 operating specifications, there has been a consistent mismatch in the sodium to chloride molar ratios. Source term studies have determined the source of the sodium to be condensate demineralizer operations. It was not uncommon for molar ratios to increase from the typical 2-5 range to over 20 following placing a new bed in service. The major cause for the caustic environment was the method of operating the condensate demineralizer. The caustic conditions have improved but continue to exist despite numerous enhancements to the operation of the systems.

A. CAUSTIC-SULFATE ENVIRONMENT (cont.)

In addition to the caustic environment, condensate demineralizer operations have provided a source of sulfate which is known to increase the rate of IGA in a caustic environment. Sulfate species can be introduced to the steam generator by either incomplete resin separations/rinses or from breakdown of the resin beads into "fines." There have been two known resin intrusions throughout Unit 2's operating life (July 1991 and February 1992). No detectable increase in steam generator blowdown sulfate concentrations was detected during 1991; however, the sulfate concentration exceeded the EPRI specification following the 1992 event. The source of these resin intrusions were identified and subsequent corrective actions were taken to repair the resin retention screens. It is also possible that a chronic inleakage of resin fines has occurred in all three units. EPRI studies have indicated that a typical PWR with full flow condensate demineralizers may throw well in excess of 100 pounds per year of resin fines to the steam generators.

With regards to sampling the steam generators, prior to 1993 the designated sample point was the hot leg blowdown. The sample point was changed to a downcomer sample point in 1993. The site was aware that the hot leg and downcomer sample points differed by a factor of 5 (approximate) as early as 1987 due to information obtained during a series of lithium tracer injection tests. Available data suggested a partial dilution of the hot leg blowdown with incoming feedwater that short-circuited over the divider plate. It is currently believed that the downcomer sample point is more indicative of the chemical environments in the upper bundle regions.

VI. ROOT CAUSE OF FAILURE DETERMINATION (CONT.)

B. CREVICE FORMATION

While IGA/IGSCC in caustic environments is a well understood condition for tube support and tubesheet crevices, the formation of freespan crevices appears to be a new phenomena. Physical evidence from video inspections performed in the space left by tube section removal confirmed the presence of bridging deposits in locations where the normal tube triangular pitch spacing is reduced to nearly tube-to-tube contact (see Figure V.D Picture 3). Evidence of tube bowing or bending was found in sections of tubes removed from the 08H-09H regions (see Figure V.L.1 through L.6). Additionally, a number of ECT-detected linear deposits occurred in tube pairs (see Figures V.P.17 and V.P.20). While these observations indicate that reduced tube spacing is occurring within the higher elevations of the tube bundle, an exact quantitative determination of the number of affected tubes was not feasible. It is evident from the evaluation of paired deposits that there are several hundred tube-to-tube crevices in the upper bundle region.

An important factor which contributed to the buildup of deposits was the high iron transport to the steam generators. Feedwater iron concentrations have historically been within the range of the EPRI specification; however, these values are considered by today's standards to be too high. Previously, the specification was <20 ppb iron (established in October 1982). The specification was reduced to <10 during 1992, and finally to <5 in the current revision dated May 1993. Iron transport studies indicated that Palo Verde feedwater concentrations were approximately 16 ppb at a typical pH of 9.0 with full flow condensate polishing. Following the study, the pH was increased and optimally controlled at 9.15 (1992) which resulted in an average feedwater iron concentration of 11 ppb. Most recently, the iron transport has been reduced dramatically by implementing an alternate pH control chemical at Unit 1 and by increasing the pH with bypass operations at Unit 3. Feedwater iron concentrations are less than 5 ppb under these conditions.

A definitive cause for the freespan crevices could not be determined during this investigation. However, based on the generator design and configuration, some qualitative reasons could explain the presence of freespan crevices.

B. CREVICE FORMATION (cont.)

The tube "bowing" or reduced tube spacing appears predominantly in the upper region of the bundle in longer unsupported tube sections (see Figure V.F.9). There are indications that similar tube space reductions could occur in the vertical sections contained within multiple eggcrates. The Task Force investigated both design and fabrication information to determine if a significant feature could lead to tube-to-tube contact in either the cold or hot condition. The design of the upper bundle supports (i.e., Batwing and Vertical Straps) does not prevent possible lateral or in-plane tube movement which could create reduced tube-to-tube spacing (see Figures VI.B.1 and V.P.1). Such movement, especially in relatively long unsupported tubes (see Figure V.F.9), could result from original bundle fabrication, restricted thermal expansion or a higher than design dead weight loading on the horizontal tube sections from the vertical supports. Either one or a combination of these factors could result in a less than nominal gap between adjacent tubes.

The relative scatter within the arc region of defects (see Figures V.A.1 and V.A.2) and deposit indications (see Figures V.P.17 and V.P.20) could also be attributed to a fabrication variation in the tube manufacturing or bending process. Since a majority of paired deposits appear to be column oriented, a bowed condition along the extrados of the bend tangent could be theorized.

The video examinations conducted during the tube pull operation further supports the extent and randomness of this condition. With respect to deposits, the video examination in the tube lanes of the pulled tubes identified three examples of close tube-to-tube proximity with a thicker axial deposit buildup bridging the area where the tubes were closer together (see Figure VII Picture 3). Similarly, two other tubes displayed a distinct, thicker axial deposit buildup where the tube had been in proximity with the removed tube. Each of the four flawed long length tubes pulled from the steam generator included visual evidence of near-contact and resultant bridging deposits. The video also confirmed the presence of a deposit and bridging over five additional flaws on tubes which were not pulled.

Based on the video and laboratory results, the Task Force attempted to further support the correlation of deposits to defects using ECT techniques. The video results were compared to the results of eddy current testing with the MRPC. The eddy current analysis identified the presence of a deposit on six out of eight of the bridging deposits viewed on the video. The classification of deposits was largely judgmental by the eddy current analysts, thus smaller signals may not be classified, explaining the fact that not all visual observations were classified.

B. CREVICE FORMATION (cont.)

Axial deposits were identified over 56 of the 103 mid-span axial cracks (12 of 16 in SG 21, 44 of 87 in SG 22). In addition, deposits were detected at the same height of an immediately adjacent tube in 50 of the mid-span cracks (9 in SG 21, 41 in SG 22,) which was considered to be evidence that reduced spacing and deposit bridging had occurred at those cracks. Based on the comparable results of eddy current testing to the video observations, additional examples of adjacent deposits (without flaws) were located. These tube locations were also assumed to be closer together with bridging deposits. Based on a review of the ECT data, 110 sets of deposits (227 tubes) were identified in SG 21 and 65 sets (131 tubes) in SG 22. These 358 tubes are assumed to be potential future crack initiation sites and therefore will be monitored in future ECT inspection programs. Additional locations may exist, since experience has demonstrated that some deposits are not classified, as discussed above.

Forty-seven (47) of the mid-span axial cracks did not include indications of deposits. Thirty-two (32) of the cracks without indicated deposits were located in the area immediately above the batwing where the vertical tube begins to enter the radius, as depicted in Figure IX-c. Although no associated flows were detected, 334 examples of deposits were noted in the same area, including 73 pairs of adjacent tubes. The lack of deposit indication at the same flaws may be due to deposit detectability as the tubes begin to move away from each other.

C. CONTAMINANT CONCENTRATION IN CREVICES

The deposit accumulation was enhanced in areas where reduced tube spacing was observed. Contaminant concentration in the deposit appears to increase with the extent of deposit.

The bridging deposits had not only a general composition of iron oxide, similar to typical scale or fouling particulates, but also had higher than normal chemical contaminant concentrations. There was no evidence that bridging deposits could develop in areas of normal tube spacing. The bridging deposit acted as a "host" for the chemical contaminants, which increased in concentration due to steam blanketing in the higher levels of the tube bundle as described in the deposit parameter model. Under examination in the laboratory, the most severe IGA and IGSCC was observed under the bridging deposits.

This is consistent with previous industry observations that severity of chemical attack is greater in areas of thick sludge buildup. This is also supported by the notion that thicker deposits (and bridging deposits) create areas of localized temperature elevation. The temperature is elevated due to the increased resistance to heat transfer through the deposit. Elevated temperature makes the crevice condition more severe and increases the concentrating effects of the crevice. This concentration of chemical species in the crevice deposits is dramatic and establishes severe conditions at the tube surface.

OD initiated cracks at the flow distribution plate, eggcrate supports and freespan crevices could therefore be expected based on the chemistry and laboratory results. However, since the majority of defects were detected within a defined arc-shaped region, a thermal-hydraulic analysis was performed to determine if a concentrating effect could be confirmed analytically. The APS ATHOS II model predicted that the arc-shaped region, as empirically defined by the eddy current testing, was a region of high deposition within the System 80 steam generators. The deposit parameter, combined thermal hydraulic results with a quality-related, non-volatile chemical concentration to provide a mechanistic understanding of the most probable location for the observed chemical deposits. This condition may be aggravated even further by a reduced recirculation ratio and ineffective SG blowdowns. Additional conducive factors identified by the Task Force, such as previously high corrosion product transport levels and lengthy continuous 100% power run times, could also exacerbate crevice conditions.

D. FLOW INDUCED VIBRATION

Flow induced vibration has been the hardest factor to quantify. SG 22 has significantly higher wear than any other SG at Palo Verde when compared at similar operational age. Comparison of the wear in SG 22 and SG 21 qualitatively correlates to a comparison of tube degradation in the two generators. This suggests that the wear and degradation of tubes may be related. The location of the rupture in SG 22 corresponds to the point where maximum displacement would occur during vibration in the unsupported tube section. The presence of wear and impact marks on pulled tubes has also been observed.

Since wear is indicative of relative motion between tube and support structure, it seems to indicate vibration is occurring. To evaluate this possibility analysis was performed to determine the susceptibility of the tubes to vibration in the thermal-hydraulic conditions modeled by the ATHOS code. The results indicated that in the modeled flow conditions the presence of flow induced vibration (fluid-elastic instability) and unsteady momentum was not likely unless certain supports were considered inactive. Additionally, the pulled tube examinations did not reveal any signs of fatigue which is associated with these type of high amplitude FIV mechanisms. However, flow induced vibration may also produce a high cycle/low amplitude applied Hertzian contact stress which could act as a crack accelerator for existing tube degradation. The affects of this type of vibration would be to accelerate crack growth rate, yet not necessarily damage tube surfaces to the extent that could be identified by examination. Continued evaluation of the flow conditions in the Unit 2 steam generators with flow oscillation as well as a degraded circulation ratio and future inspection results of the Unit 1 and 3 steam generator tubes (which are historically free of excessive tube wear) may help determine the exact role of FIV tube degradation.

E. SURFACE RESIDUAL STRESSES, COLD WORKING/SCRATCHES

Several axial cracks at freespan and eggcrate locations were associated with surface scratched areas. The more severe scratched areas associated with ridged, concentrating deposits showed the deepest corrosion attack and the longest crack length. Scratched areas result in tube surface cold working, with resultant surface tensile residual stresses. Cold worked areas are considered to be preferential sites for IGA and IGSCC, leading to a more rapid crack initiation. Intergranular attack has been shown in laboratory tests to occur at cold worked sites which contained either tensile or compressive residual stresses. The source of cold worked scratched areas has not been determined, although damage due to the bending process, tube installation and tube-to-tube contact has been postulated to be potential sources of damage.

F. TUBE MANUFACTURING/MICROSTRUCTURE

Microstructural characterization of some pulled tubes showed a microstructure absent in *intra*granular carbide precipitation, with slight *inter*granular carbide precipitation. This microstructure is not as expected for a typical high temperature mill annealed Alloy 600 material which would normally have a semi-continuous grain boundary carbide precipitation, thus providing more IGSCC resistance in caustic environments. The cause of this microstructure was probably a combination of the heat treatment/cooling process and low carbon content.

The significance of the poor microstructure is that the material's resistance to a caustic environment is reduced. Laboratory testing has indicated that the absence of grain boundary carbides reduces the materials resistance to cracking in a caustic environment.

Microstructural characterization of tubes varied but were less than what is recognized as optimum today. The presence of intragranular and intergranular carbides and prior carbide grain boundaries indicates that the annealing heat treatment was not a full solution anneal which would have dissolved all carbides, promoted grain growth and provided an inventory of carbon for grain boundary precipitation during cooldown. This results in a lower material resistance to intergranular cracking in the caustic environment. Microstructure evaluation of examined tubes showed a marginal but acceptable tube microstructure.

VI. ROOT CAUSE OF FAILURE DETERMINATION (CONT.)

G. EDDY CURRENT TESTING

The detectability comparisons of bobbin and MRPC axial crack indications were based on average through-wall depth. The eddy current detectability threshold for 100% detection, based on average crack depth, is 50% through-wall for bobbin and 40% through-wall for MRPC.

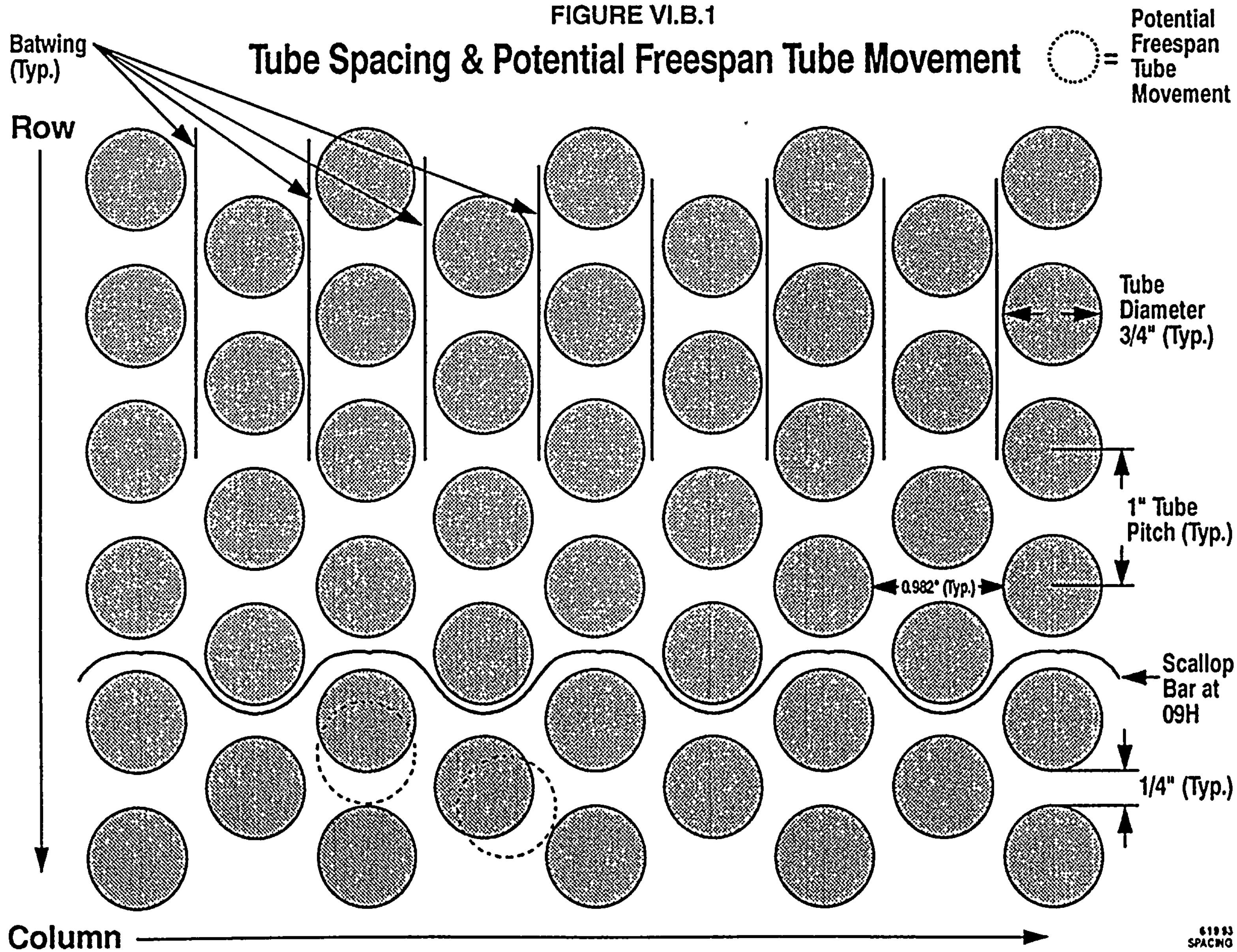
Also, to determine which comparison is appropriate for use as a detectability threshold, a comparison of the actual burst pressures versus the predicted burst pressures based on average and maximum crack depths is provided in Table V.B.1 and illustrated in Figure V.B.5. The comparison demonstrated that a correlation with actual burst pressures can be achieved using the average crack size. Thus, the average crack size is more indicative of the structural integrity of the tube than the maximum crack size. Therefore, 50% average through-wall depth will be used as the bobbin coil detectability threshold. Similarly, 40% through-wall will be used as the MRPC detectability threshold.

CONCLUSION

The evidence indicates that the rupture of tube R117C144 was due to IGA/IGSCC which occurred as a result of tube-to-tube crevice formation. The crevice, together with the consequential heat flux, led to an aggressive environment under a ridge deposit. As a consequence, a long deep crack initiated under the ridge deposit, leading to the loss of structural integrity under normal operating conditions. Several additional contributing factors such as increased sulfate levels due to resin intrusion, likelihood of cold working due to surface scratches, flow induced vibration, less than standard microstructure in R117C144, and increased susceptibility of contaminant concentration in the upper region of the tube bundle were also identified.

FIGURE VI.B.1

Tube Spacing & Potential Freespan Tube Movement



VII. OTHER SUSCEPTIBLE ITEMS

The Unit 1 and Unit 3 steam generators are the same design and were constructed and operated essentially the same as the Unit 2 steam generators. Based on these conditions, Unit 1 and 3 steam generators are considered to be susceptible to the failure mechanism described in this report. A separate study was performed to evaluate the transportability of Unit 2's tube degradation problems. This study was issued to the NRC (Letter 102-02585-WFC/TRB/RAB, July 25, 1993) and provides information on the ECT performed in Unit 2, compares the findings of the Unit 2 inspection to Units 1 and 3 and evaluates the safety significance for the continued operation of Units 1 and 3 with potentially degraded tubes. In summary, this report states that tube degradation potentially exists in Units 1 and 3, but based on the known intrusion of secondary demineralizer resin in Unit 2 SG's and differences in the ECT results, the other two units may not have the same problem at this time. Inspection plans have been developed for the Unit 1 outage to evaluate the generators for similar conditions as those seen in Unit 2. Additionally, the actions listed in the following section will also be incorporated in the other units.

VIII. CORRECTIVE ACTIONS

The ERCFA team has been unable to determine the root causes or the relative importance of the identified contributing factors. In addition to the corrective actions identified in this section, the RCF team recommends that the RCF investigation continues to further quantify and validate these factors as more information is obtained from future SG tube inspections. A summary of the Corrective Actions is on Table VIII.A located at the end of this section.

A. SPECIAL EMPHASIS AREAS

1. Attempt to establish the exact cause of tube to tube crevice formation. Determine if the phenomena exists in Units 1 and 3.
2. Continue thermal-hydraulic modeling of the SG's with ATHOS III and develop a more complete understanding of the susceptible regions of the SG.
3. Evaluate the effect of microstructure on tube degradation. Correlate damage tubes to specific heat treatment lots through CMTR's.
4. Evaluate the designed and/or degraded circulation ratio for its impact on several of the identified factors. For example, the potential for flow induced vibration could be greater than analyzed if SG circulation ratio is degraded. A decreased circulation ratio would produce higher deposition in the upper bundle and a concentration of chemical contaminants (due to dryout) in upper deposits. This degradation could also be the major contributor to the excessive wear seen in the Unit 2 steam generators.

Corrective actions to address the IGA/IGSCC and its effect on steam generator integrity and plant operability are grouped into various categories and discussed below. These include actions to be taken prior to restart, those to be implemented during operation, and long term actions, as well as improvements, in leak detection monitoring and operator response.

B. ACTIONS TAKEN PRIOR TO RESTART

1. Condensate Demineralizer (CD) Inspection

Since the presence of sulfate from resin intrusions is considered a factor in the steam generator tube degradation observed in Unit 2, all seven CD vessels were inspected during U2R4 and repaired as necessary to ensure resin retention elements are in good working order. The following is a summary of the repairs completed prior to restart:

a. Service Vessel A - Five failed retention elements repaired/replaced, resin trap replaced.

b. Service Vessel F - Two failed retention elements repaired/replaced, resin trap replaced.

c. Service Vessel C - Liner and concrete damage repaired.

d. Service Vessel E - Resin trap strainer replaced.

B. ACTIONS TAKEN PRIOR TO RESTART (cont.)

2. **Steam Generator Drain and Fill**

After completion of the tube pull operations and tubesheet plugging, the steam generators were placed in a wet layup condition (pH of 9.5, nitrogen overpressure >5 psig and hydrazine >100 ppm). While in this layup condition, sulfate continued to be solubilized from the deposits, increasing to greater than 50 ppb (well within the EPRI specifications). To minimize contaminant loading in the SG and the secondary system, the SG's were drained and refilled with condensate storage tank water.

3. **Steam Generator Plugging and Staking**

PVNGS Technical Specifications Section 4.4.4.4.a.6 requires steam generator tubes to be removed from service if a defect exists which is greater than 40% of the nominal tube wall thickness. APS Nuclear Engineering has developed a conservative plugging criteria based on defect type and Regulatory Guide 1.121 limits. Currently the PVNGS Engineering Plugging Criteria applied for U2R4 is as follows:

a. Tubes with wear indications ≥20% for Stay Cylinder Batwing and Cold Leg Corner wear.

b. Tubes with wear indications ≥35% for all other support locations previously examined with no wear detected, or if the tube had not been ECT inspected in the previous outage.

c. Tubes with wear indications from 39% ≥x ≥35% for locations that had previous indications ≥20% need not be plugged.

d. All PLP's with any detectable wear.

e. All suspected cracks.

f. All SVI indications whose bobbin coil examinations have shown a change in any of the last three ECT inspections.

B. ACTIONS TAKEN PRIOR TO RESTART (cont.)

Tube stabilization requirements are specified in N001-6.03-440, Steam Generator Tube Stabilizer Staking Report/Guidelines for PVNGS. Typically tubes are stabilized for stay cylinder batwing wear, cold leg corner wear and PLP locations. The removal of tube sections in SG 22 resulted in a unique configuration which required additional analysis to assure that the remaining sections of tubes did not pose a concern to active tubes in the steam generator. The tube pull contractor, BWNS, utilized its standard 2-D FIV code to qualify the stabilized condition. This was accomplished by first performing an analysis of the original tube and support configuration to determine its fluid-elastic stability margin and maximum turbulence response. An analysis was then performed for the cut and stabilized tube and the resulting stability margin and turbulence response was determined relative to the original condition. If the cut and stabilized tube stability was equivalent or better than the original condition, this was considered to be an acceptable stabilization of the tube. APS Nuclear Engineering and ABB-Combustion Engineering independently verified the tube stabilization methodology.

The remaining tube ends for the pulled tubes at Palo Verde Unit 2 SG 22 fall into three categories. They are:

Case 1: Tube cut above 08H or 09H and the tube end is not fully restrained horizontally.

Case 2: Tube cut below 09H and the tube end is fully restrained horizontally.

Case 3: Tube is cut below 03H and the tube end is fully restrained horizontally.

Tubes which were not cut below a captured horizontal support (Case 1) have been analyzed and determined to be effectively stabilized by a 0.5 inch diameter stainless steel cable extending from the cold leg side tubesheet to the tube cut end. The cable was attached to the cold side tubesheet plug. As an additional conservative measure, adjacent tubes will be plugged and stabilized in a containment pattern around the pulled tube.

Tubes which were cut below a horizontal support (Case 2) result in a tube end fully restrained in the horizontal direction. These tubes were effectively stabilized by a 0.5 inch diameter stainless steel cable extending from the cold leg side tubesheet to the tube cut end. The cable was attached to the cold side tubesheet plug. The analysis performed for the Case 1 tubes enveloped the tubes in this category.

Tubes cut low (Case 3) did not require stabilization. The tube response above 08H was not significantly influenced by the tube end conditions at 03H.

C. OPERATIONAL CORRECTIVE ACTIONS

Palo Verde Site Chemistry formalized a plan in December, 1992, to reduce the potential for steam generator related power generation losses and to extend steam generator life. The scope of this plan was to address the concern of IGA/IGSCC, primarily due to caustic bulk water conditions and iron transport (crevice formation). The relationship of all the secondary chemistry control objectives is referred to as min/max chemistry (see Figure XI-a). The operational objectives are to minimize contaminant level input into the steam generator, maximize the return or removal of contaminants from the SG and mitigate the corrosive environment in the SG. With the exception of boric acid and planned periodic downpowers, the majority of these objectives have already been implemented in Units 1 or 3. Preliminary indications of those control objectives that are measurable demonstrate relative success. Unit 1 has maintained the molar ratio (ratio of sodium to chloride) less than one. The control of this parameter is a leading indication of the neutralization of the SG crevice environment. During a recent shutdown in Unit 1, the hideout return chemistry (MULTEQ) analysis (lagging indicator) was substantially less caustic (near neutral) than what had been measured previously.

The root cause of failure for the Unit 2 SGTR event identified the bulk secondary chemistry environment of the SG as a contributory factor. However, not all secondary system corrective actions can be implemented prior to restart or during initial startup. Some operational corrective actions are dependent on stabilizing the unit after startup. The corrective actions have to be consistent with concerns of a contaminated secondary system cleanup and water processing. Planned operational corrective actions to address the alkaline environment and deposit formation during Cycle 5 are as follows:

1. Molar Ratio Control

The most difficult control parameter is the ratio balance of cations to anions in the crevices to prevent the formation of caustic or acidic environments. Molar ratio control has been best achieved in PVNGS Units 1 and 3 by partial or full CD bypass and a continuous CD system performance improvement program. Once Unit 2 is stabilized after restart, CD operation will be manipulated to control the molar ratio within approved operating specifications.

C. OPERATIONAL CORRECTIVE ACTIONS (cont.)

2. Minimize Contaminant Source Term Input

Contaminant source term inputs to the steam generators will be minimized, dependent on plant conditions. Contaminants have been shown to concentrate in SG crevices and tube deposits. Source term studies at PVNGS have indicated that the condensate demineralizers have been the primary source of sodium. Chronic leakage of sulfate from regenerate chemicals and resin fines were determined to be the source of sulfate ingress. The CD performance improvement program will be implemented during Cycle 5. Additionally, a resin monitoring program will be implemented to identify if a resin intrusion event has occurred and to alert plant staff to a potential maintenance issue.

3. Reduce Iron Transport

Iron transport to the SG's is the primary makeup source of deposits. The bridging and support deposits, known to have contributed to the IGA/IGSCC, are comprised primarily of iron oxides. Iron transport will be minimized and maintained within new, lower plant operating specifications. Currently, Units 1 and 3 utilize elevated pH to control corrosion product transport. Unit 1 has recently converted to Ethanolamine (ETA) for pH control while Unit 3 continues to inject ammonia as its pH additive. Unit 2 will not start up on ETA (because of radwaste water processing concerns), but ETA will be slip streamed in once stable conditions have been achieved. Dependent on plant conditions, pH will be optimized, in Unit 2, by either ETA or ammonia addition to reduce iron transport. The pH will be increased and the condensate demins will be removed from service as necessary.

4. Elevated Hydrazine

A corrosive environment can be mitigated by operating secondary chemistry with elevated hydrazine. Feedwater hydrazine levels will be maintained according to plant operating procedure specifications during Cycle 5. The elevated hydrazine level (>100 ppb) will ensure that a reduced electrochemical potential environment exists, thereby increasing resistance to IGA/IGSCC.

C. OPERATIONAL CORRECTIVE ACTIONS (cont.)

5. Blowdown Optimization

PVNGS intends to maximize SG blowdown efficiency during Cycle 5 operation. Blowdown is the only means to remove contaminants from the steam generator. The blowdown schedule will be optimized, using normal, abnormal and high rate blowdown to control SG contaminant levels and maintain proper molar ratio control. Blowdown optimization will be a specific task undertaken by the Steam Generator Working Group.

6. Maximize Hideout Return via Periodic Downpowers.

Downpowers have been shown to be effective in solubilizing contaminants such as sodium, sulfate and chloride. The film boiling surface is collapsed in the high quality location in the bundle, wetting the previously dried out area. Downpowers will be scheduled dependent on source loading (i.e., condenser tube leak amount or degree of condensate demineralizer usage) and downpower effectiveness. As the hideout return is reduced, the time between downpowers is increased. Beginning approximately one month after startup, periodic downpowers will be conducted.

D. LONG TERM CORRECTIVE ACTIONS

1. Boric Acid Treatment

Implement boric acid treatment in the secondary system to mitigate the alkaline/caustic crevice environment.

Boric acid treatment will be implemented per PCR 92-13-SC-002.

2. Mossbauer Analysis and/or Electrochemical Potential Measurements.

Both of these techniques can be used to determine whether an oxidizing environment is present in the SG's. Mossbauer Analysis determines the hematite/magnetite ratio in corrosion product samples which is significant because corrosion rates are dependant upon ECP. ECP measurements are in situ measurements in the SG. ECP measurements will be considered as to its economic benefit and will be evaluated by Chemistry and Nuclear Engineering.

3. T_{hot} Reduction

PVNGS is currently involved in evaluating the benefits and impact of T_{hot} reduction. Elevated T_{hot} is a contributing factor in the occurrence of IGA/IGSCC. This evaluation is projected to be completed in 1994.

4. Chemical Cleaning

Chemical cleaning presentations have been made by three vendors. A Request for Proposal is being completed for vendor solicitation. Nuclear Engineering is evaluating the economic benefit and timing of chemical cleaning.

5. ATHOS III Run

EPRI's ATHOS III model is being run to evaluate the impacts of varying flow, level and deposit parameters. This run is ongoing and is expected to be completed by July 19, 1993. Based on the information from this analysis other operational corrective actions will be developed and evaluated.

6. Improved Eddy Current Technology

Improved technology is being researched to enhance sensitivity, detectability and speed of eddy current techniques.

E. PRIMARY-TO-SECONDARY LEAKAGE MONITORING

The primary-to-secondary leakage monitoring program was designed to address three specific scenarios.

1. **Low Level and/or Slowly Increasing Primary-to-Secondary Leakage**

2. **Rapidly Increasing Primary-to-Secondary leakage (as described in IN-91-43)**

3. **Steam Generator Tube Rupture (no leak before break)**

   This program was reevaluated to ensure that it also encompassed the actual scenario observed during the Unit 2 SGTR event. This effort validated the adequacy of the existing leakage monitoring program; however, some areas for enhancement were identified.

4. **Leakage Monitoring Program**

   The leakage monitoring program utilizes the installed Radiation Monitoring System (RMS) to detect the level and the rate of change of radioactivity in the secondary plant. The RMS provides continuous on-line monitoring capability to both Operations and RMS/Chemistry personnel for detection of primary-to secondary leaks. The RMS monitors used for primary-to-secondary leak detection are described below:

   a. Steam Generator Blowdown Radiation Monitors (RU-4 and RU-5)

      Blowdown (downcomer sample point preferred) from each steam generator is monitored for liquid radioactivity (gamma emitters).

   b. Condenser Vacuum Exhaust/Gland Seal Exhaust Radiation Monitor (RU-141)

      The exhaust from the condenser vacuum pumps and gland seal exhaust blower discharge into a common line that is monitored for radioactive noble gases.

   c. Main Steam Line Monitors (RU-139 and RU-140)

      Dose rates on the main steam lines are monitored for increasing levels resulting from contaminated steam. While these monitors are not useful for detecting small leaks, they will provide an immediate indication of the larger leak rates associated with a SGTR event.

E. PRIMARY-TO-SECONDARY LEAKAGE MONITORING (cont.)

5. Routine Sampling

In addition to the RMS, the Chemistry Department also performs routine sampling in order to detect primary-to-secondary leakage once per 72 hours to determine gross activity concentrations of the secondary coolant system (steam generators) per Technical Specification 3.7.1.4. This surveillance test uses gamma spectroscopy methods to determine radionuclide concentrations in the secondary coolant. This analytical method has a leak rate detection capability of 1.9 gpd (based on reactor coolant Iodine-131 activity of 4E-03 µCi/gm from fuel cycle data).

Under normal conditions, when no steam generator primary-to-secondary leakage is present, RU-141 trend data are reviewed for three-fold increases on at least a shiftly basis. In addition, setpoints on RU-141, RU-4 and RU-5 will alert personnel to increases in baseline monitor readings resulting from an increase in radioactivity levels in the secondary system. Routine chemistry sampling of the secondary system, performed in accordance with the Technical Specifications, will also alert personnel to the presence of low level concentrations of activity that may be below the sensitivity of the monitoring instrumentation. Based on the Unit 2 experience, low level leakage should exist for an extended period (on the order of several weeks) prior to significant increases in leak rate. Therefore, the existing monitoring program is adequate to detect the onset of primary-to-secondary leakage.

6. Procedure Requirements

Procedure 74RM-9EF41, "Radiation Monitoring System Alarm Response," directs operations personnel to evaluate the secondary system for steam generator leakage in accordance with Procedure 4XAO-XZZ08, "Steam Generator Tube Leak," upon receipt of a valid alert or high alarm on any of the secondary system monitors. In addition, Chemistry personnel are also directed to perform a leak rate determination in accordance with Procedure 74CH-9ZZ66, "Determination of Primary to Secondary Leak Rate" and evaluate/monitor the leakrate in accordance with Procedure 74DP-9ZZ05, "Abnormal Occurrence Checklist." If activity is detected during the performance of Procedure 74ST-9SG01, "Secondary System Activity Surveillance Test" and/or Procedure 74ST-9ZZ02, "Chemical Waste Neutralization Surveillance Test," chemistry personnel are directed to notify operations and perform a leak rate determination in accordance with Procedure 74CH-9ZZ66 and to evaluate/monitor the leak in accordance with Procedure 74DP-9ZZ05. Once primary-to-secondary leakage is identified and confirmed, the leakrate monitoring instructions and decision levels contained in Procedure74DP-9ZZ05 are implemented.

E. PRIMARY-TO-SECONDARY LEAKAGE MONITORING (cont.)

The monitoring instructions contained in Procedure 74DP-9ZZ05 are based on leak rate levels. The higher the leak rate, the more aggressive the monitoring program. The decision levels for evaluating continued plant operation are contained in Procedure 4XAO-XZZ08. Additionally, this procedure requires evaluation of the impact of the leak rate on plant operations by operations personnel and plant management. Based on experience from the Unit 2 event, the leak rate levels for leak monitoring and evaluation will be changed as described below.

7. **Leak Rate Monitoring and Evaluation**

In addition to the enhanced leak monitoring program, specific administrative actions will be taken at various leak rates and rate of change. Between 0 and 10 gpd, the monitoring schedule as described previously will be conducted. When the leak rate is greater than 10 gpd and the leak rate increases by 50% within a 24 hour period, or a stable leak rate of 25 gpd is reached, a formal evaluation for continued operation will be conducted. The evaluation process will consider items such as RCS source term, stability of the leak, waste water processing abilities and the leak rate trend. If the leak rate exceeds 50 gpd, the Shift Supervisor initiates an orderly plant shutdown, and then informs plant management.

SGTR events (i.e., leak rates in excess of 40 gpm) are easily detectable by the main steam line monitors as evidenced by the Unit 2 event. Emergency Operations and Abnormal Occurrence procedures have been modified to ensure an accurate diagnosis of the event based on experience obtained from the Unit 2 event.

F. PROGRAM ENHANCEMENTS

Based on experience gained from the Unit 2 event and reevaluation of the leak rate monitoring program at PVNGS, several enhancements were identified. These enhancements either have been incorporated or will be incorporated into the existing program. The following summarizes these enhancements and provides a status for those that are in progress.

1. Steam Generator Blowdown Radiation Monitors (RU-4 and RU-5)

The sensitivity of the Steam Generator Blowdown Radiation Monitors, RU-4 and RU-5, have been improved by selecting the downcomer instead of the hot leg blowdown as the monitoring point. The downcomer sample stream, which is more concentrated, offers greater overall sensitivity to detect primary-to-secondary leakage.

2. Condenser Vacuum Exhaust Monitor (RU-141)

The alert setpoints for Condenser Vacuum Exhaust Monitor, RU-141, has been decreased to a level that is four times above background readings. The former setpoint value was based upon an allocated fraction of the site instantaneous dose rate limits per the off-site dose calculation manual and was several decades above typical baseline values. The new setpoints for RU-141 provide earlier alarms to plant operators in the event of increasing primary to secondary leakage than the previous setpoints.

3. Procedure 74CH-9ZZ66, Determination of Primary-to-Secondary Leak Rate, Method Priorities

Based on the Unit 2 SGTR event, as well as industry information, the preferred hierarchy of leak rate methodologies is to use a noble gas grab sample from the condenser vacuum exhaust for the most accurate leak rate determination. Iodine in the steam generator bulk water may be utilized if the leak is so small that noble gases are not detected in the condenser vacuum exhaust grab sample. However, industry information suggests that iodine may hideout in the steam generator and therefore underpredict the actual leak rate. If noble gas can be detected in the condenser vacuum exhaust, it should be utilized for leak rate quantification with iodine being used for a qualitative confirmation of trend and to identify the leaking steam generator. The tritium method should be utilized in the absence of other radionuclides.

F. PROGRAM ENHANCEMENTS (cont.)

4. **Leak Rate Administrative Action Plan**

Dependent on the primary-to-secondary leak rate, the monitoring frequency will be increased. The monitoring program includes leak rate calculations, monitor trend data, and monitor setpoints. In addition, a formal evaluation for continued operation will be conducted when a 10 gpd leak rate increases by more than 50% in a 24-hour period, or a stable leak rate of 25 gpd is reached. At 50 gpd, the Shift Supervisor initiates an orderly plant shutdown, then informs plant management.

5. **N-16 Monitoring**

PVNGS Engineering has conducted a preliminary evaluation regarding N-16 monitoring instrumentation. As part of the evaluation, all major manufacturers of N-16 monitors were contacted. In addition, utilities that were currently using N-16 monitors were contacted to determine their installation and operational experience with the instrumentation. Based on the evaluation, the advantages of N-16 were determined to be a rapid response time and a source term that was only dependent on reactor power. The disadvantages included a large error due to inaccuracies in estimating transport time through the steam generator and high installation cost. The short half life of N-16 makes quantifying the leak rate highly dependent on leak location. An accurate estimate of leak rate would still require correlation to conventional grab samples. PVNGS has committed to the use of portable N-16 monitors as a diagnostic tool for determining leak location and their benefit in giving a more timely notification of an increase in leak rate.

The RMS response and leak monitoring program at PVNGS was reevaluated based on information obtained from the Unit 2 SGTR event. The evaluation verified that the current program adequately addressed early leak detection within the guidance of Information Notice 91-43. During the two weeks prior to the rupture, the RMS responded to minor leak transients. The main steam line monitors and the condenser exhaust monitor provided immediate indication of a SGTR when it occurred. It was concluded that for this event, the addition of N-16 monitors would not have provided any additional information that could have prevented the SGTR. Instead, the leak rate monitoring program was changed to (1) ensure correct diagnosis of a SGTR event by incorporating changes to the EOP's to use previous alarm indications and trend data, (2) provide earlier alarm indication by lowering the setpoint on the condenser exhaust radiation monitor and changing the sampling location for the steam generator blowdown monitors, and (3) improve alarm response actions and leak rate estimates by utilizing condenser exhaust grab sample results as one of the primary leak rate calculation methods.

Table VIII.A
CORRECTIVE ACTION SUMMARY

SECTION VIII	CORRECTIVE ACTION	RES. MGR.	PRI	DUE DATE
A.1	Develop the criteria necessary to help establish the exact root cause of the tube-to-tube crevice formation. Determine if phenomenon exists in Units 1 and 3.	R. Schaller	3	3/1/94
A.2	Develop a complete understanding to confirm the susceptible regions of the SG for crevice formations. Continue the thermal-hydraulic modeling of the SG's with ATHOS III.	M. Hodge	3	12/31/93
A.3	Investigate whether PVNGS can correlate the damaged tubes to specific heat treatment lots through CMTR's.	R. Schaller	3	11/15/93
A.4	Evaluate the designed and/or degraded circulation ratio for its impact on potential dryout of the tubes in the upper SG bundle.	R. Schaller	3	12/31/93
C.1	Molar Ratio Control - Upon stabilization of Unit 2 after restart, manipulate the CD operation to control the molar ratio within approved operating specifications. Make appropriate procedure changes as necessary.	L. Johnson	3	10/1/93
C.2	Minimize Source Term Input - Implement the CD performance improvement program during Unit 2 Cycle 5.	J. Scott	3	6/1/95
C.2	Minimize Source Term Input - Implement the resin monitoring program to identify if a resin intrusion event has occurred and to alert plant staff to a potential maintenance issue.	J. Scott	3	Done 74DP-9ZZ05

Table VIII.A
CORRECTIVE ACTION SUMMARY

SECTION VIII	CORRECTIVE ACTION	RES. MGR.	PRI	DUE DATE
C.3	Reduce Iron Transport - Upon Unit 2 stabilization, slip stream in ETA to help control the pH and eventual corrosion product transport.	L. Johnson	3	11/1/93
C.4	Elevated Hydrazine - Maintain the feedwater hydrazine levels in accordance with operating procedure specifications during Unit 2 Cycle 5.	L. Johnson	3	10/1/93
C.5	Blowdown Optimization - Implement the blowdown optimization program to maximize SG blowdown efficiency during Unit 2 Cycle 5 operation.	L. Johnson	3	1/15/94
C.5	Blowdown Optimization - Develop and implement the blowdown optimization program to maximize SG blowdown efficiency during Unit 2 Cycle 5 operation.	R. Schaller	3	1/15/94
C.6	Maximize Hideout Return via Periodic Unit Downpowers - Conduct periodic downpowers one month after Unit 2 startup. Change appropriate procedures as necessary.	L. Johnson	3	1/15/94
D.1	Implement the Boric Acid Treatment Program in secondary system to mitigate the alkaline/caustic crevice environment.	R. Schaller	3	3/15/94
D.2	Mossbauer Analysis and/or Electrochemical Potential Measurements - Evaluate the use and economic benefits of ECP measurements to help determine whether an oxidizing environment is present in the SG's.	R. Schaller	3	1/4/94

Table VIII.A
CORRECTIVE ACTION SUMMARY

SECTION VIII	CORRECTIVE ACTION	RES. MGR.	PRI	DUE DATE
D.3	T_{hot} Reduction - Evaluate the benefits and impacts of implementing a reduction in the SG T_{hot} operating parameter.	C. Stevens	3	08/31/94
D.4	Chemical Cleaning - Evaluate the economic benefits and possible future implementation of the Chemical Cleaning Program.	R. Schaller	3	9/30/93
D.5	ATHOS III Runs - Continue to run the ATHOS III EPRI computer model to evaluate the impacts of varying flow, level and deposit parameters.	M. Hodge	3	12/31/93
D.6	Improved Eddy Current Technology - Research the present eddy current technology to enhance the ECT sensitivity, detectability and speed. Modify current program to incorporate the new technology.	D. Garchow	3	08/31/94
E.4 & F.4	Leak Rate Monitoring and Evaluation - In addition the enhanced leak rate monitoring program, implement administrative controls/actions at various leak rates and rate of change. Modify the appropriate operating procedures as necessary.	J. Scott	3	Done 74DP-9ZZ05 74CH-9ZZ66 74DP-9ZZ14
F.3	Procedure 74CH-9ZZ66, Determination of Primary-to-Secondary Leak Rate, Method Priorities - Evaluate the use of a noble gas grab sample from the condenser vacuum exhaust for the most accurate leak rate determination.	J. Scott	3	Done
F.5	N-16 Monitoring - Evaluate the use of N-16 monitors as a diagnostic tool for determining leak location and their benefit in giving a more timely notification of an increase in leak rate.	B. Berthelt	3	12/31/93

Attachment V.P.1

Deposit Formation based on Eddy Current Examination Findings for SG 21

V.P.1-1						
Mid-span axial indications, steam generator 21						
					Associated PDP	
	Row	**Col**	**Location**	**Length**	**From**	**To**
1.	104	41	BW1+4.67"	0.26"	BW1+3.03	to 5.43"
2.	109	42	08H+34.35"	6.96"	08H+30.20	to 42.58"
3.	109	42	BW1+3.73"	0.49"	BW1+3.14	to 5.04"
4.	104	43	BW1+3.76"	0.98"	BW1+2.37	to 5.49"
5.	106	45	BW1-0.77"	0.38"	not aligned w/deposit	
6.	106	45	BW1+2.74"	1.16"	BW1+1.17	to 3.92"
7.	131	46	BW1+18.81"	0.41"	not aligned w/deposit	
8.	147	76	09H+25.44"	0.56"	09H+20.39	to 31.37"
9.	149	76	09H+24.92"	0.41"	09H+23.90	to 31.86"
10.	145	84	BW1+4.68"	0.49"	not aligned w/deposit	
11.	140	89	09H+23.34"	0.41"	09H+22.98	to 24.50"
12.	113	92	BW1+3.39"	1.01"	BW1+2.41	to 3.65"
13.	141	104	BW1+3.10"	0.31"	not aligned w/deposit	
14.	148	111	09H+27.83"	0.50"	09H+23.79	to 34.19"
15.	148	111	09H+33.90"	0.40"	09H+23.79	to 34.19"
16.	139	118	09H+24.90"	0.20"	09H+24.31	to 26.61"

Attachment V.P.1

V.P.1-2					
PDP pairs associated with mid-span axial indications, steam generator 21					
	Row	**Col**	**Location**	**Length**	**Associated PDP From To**
1.	104 106	41 41	BW1+4.67"	0.26"	BW1+3.03 to 5.43" BW1+2.93 to 4.33"
2.	107 109	42 42	08H+34.35"	6.96"	08H+27.20 to 41.49" 08H+30.20 to 42.58"
3.	104 106	43 43	BW1+3.76"	0.98"	BW1+2.37 to 5.49" BW1+2.52 to 3.80"
4.	147 149	76 76	09H+25.44"	0.56"	09H+20.39 to 31.37" 09H+23.90 to 31.86"
5.	147 149	76 76	09H+24.92"	0.41"	09H+20.39 to 31.37" 09H+23.90 to 31.86"
Note: ECT orientation confirmed that flaws and deposits for 147-76 and 149-76 were directly on column orientation, but did not confirm if they were directly facing toward or away from each other.					
6.	113 115	92 92	BW1+3.39"	1.01"	BW1+2.41 to 3.65" BW1+ 4.61 to 5.45"
7.	146 148	111 111	09H+27.83"	0.50"	09H+23.79 to 33.07" 09H+23.79 to 34.19"
8.	146 148	111 111	09H+33.90"	0.40"	09H+23.79 to 33.07" 09H+23.79 to 34.19"
Note: ECT orientation confirmed that flaws and deposits for 146-111 and 148-111 were directly on column orientation, but did not confirm if they were directly facing toward or away from each other.					

Attachment V.P.1					
V.P.1-3					
PDP pairs not associated with mid-span indications, column oriented, steam generator 21. ECT orientation is identified, if known.					
				Associated PDP	
	Row	Col		From	To
1.	31 33	6 6		07H+16.21 07H+14.72	to 21.34" to 21.26"
2.	35 37	6 6		BW-6.24 07H+18.78	to 4.30" to 26.85"
3.	44 46	7 7		07H+25.06 07H+26.06	to 31.09" to 32.40"
4.	62 64	9 9		07H+28.83 07H+15.36	to 43.36" to 41.91"
5.	58 58 60	11 11 11		07H+29.50 07H+31.43 07H+38.99	to 42.14" to 43.38" to 44.66"
6.	61 63 65	16 16 16		BW1+1.08 BW1+0.62 BW1+1.84	to 3.35" to 4.99" to 3.70"
7.	62 64	17 17		07H+32.68 07H+32.25	to 45.25" to 44.34"
8.	62 64	17 17		BW1+1.89 BW1+0.00	to 3.85" to 4.38"
9.	70 72	17 17		BW1+2.46 BW1+0.98	to 4.92" to 3.15"
10.	80 82	17 17		BW1+2.78 BW1+2.15	to 4.63" to 3.19"
11.	63 65 65	18 18 18		07H+29.46 07H+29.64 07H+30.79	to 45.37" to 45.71" to 42.48"
12.	64 66	19 19		BW1+3.90 BW1+2.44	to 5.08" to 3.43"
13.	59 61	20 20		07H+34.40 07H+34.76	to 42.27" to 42.62"

Attachment V.P.1

V.P.1-3

PDP pairs not associated with mid-span indications, column oriented, steam generator 21. ECT orientation is identified, if known.

	Row	Col		Associated PDP From	To
14.	90 92	21 21		BW1+2.14 BW1+0.41	to 5.23" to 3.80"
15.	80 82 84 86	23 23 23 23		BW1+15.01 BW1+17.14 BW1+15.88 BW1+17.30	to 31.98" to 32.84" to 33.64" to 34.57"
16.	37 39	24 24		06H+1.86 06H+1.53	to 3.23" to 4.94"
17.	30 32	25 25		07H+15.88 07H+12.15	to 18.71" to 15.05"
18.	64 66	25 25		07H+32.04 07H+31.58	to 47.56" to 43.66"
Note: Based on ECT orientation, deposits on 64-25 and 66-25 face each other.					
19.	98 100	25 25		BW1+2.52 BW1+0.64	to 5.96" to 4.75"
20.	104 106	25 25		BW1+3.51 BW1+0.12	to 5.47" to 4.11"
21.	70 72	25 25		BW1+4.10 BW1+1.69	to 5.38" to 4.05"
22.	31 33 35	26 26 26		07H+1.12 07H+1.25 07H+1.90	to 2.59" to 2.16" to 2.78"
23.	109 111	28 28		08H+17.24 08H+17.67	to 32.97" to 32.96"
24.	110 112	29 29		08H+36.56 08H+37.16	to 43.30" to 43.73"
25.	61 63	30 30		BW1+4.32 BW1+2.98	to 7.15" to 5.46"
26.	109 111	30 30		BW1+2.09 BW1+2.89	to 5.61" to 4.31"
27.	56 58	31 31		BW1+3.12 BW1+2.07	to 8.45" to 4.98"

Attachment V.P.1					
V.P.1-3					
PDP pairs not associated with mid-span indications, column oriented, steam generator 21. ECT orientation is identified, if known.					
				Associated PDP	
	Row	Col		From	To
28.	76 78	31 31		BW1+0.70 BW1+2.38	to 4.77" to 3.49"
29.	98 100	31 31		BW1+3.53 BW1+2.13	to 6.06" to 4.41"
30.	114 116	31 31		08H+16.38 08H+16.53	to 40.51" to 38.77"
Note: Based on ECT orientation, deposits on 114-31 and 116-31 faced each other.					
31.	55 57	32 32		07H+1.43 07H+1.79	to 2.95" to 2.85"
32.	107 109 111 113	32 32 32 32		BW1+2.35 BW1+2.37 BW1+2.81 BW1+2.55	to 4.52" to 5.06" to 6.11" to 5.07"
33.	114 116 116	33 33 33		08H+26.71 08H+26.87 08H+27.09	to 40.35" to 40.76" to 40.90"
Note: Based on ECT orientation, the deposit on 116-33 directly faced 114-33. The orientation of 114-33 was unknown.					
34.	60 62	35 35		07H+35.68 07H+35.16	to 45.51" to 46.95"
35.	92 94	37 37		BW1+2.24 BW1+2.73	to 4.39" to 3.04"
36.	98 100	39 39		BW1+3.50 BW1+2.27	to 5.55" to 4.02"
37.	99 101	40 40		BW1+3.90 BW1+2.01	to 5.55" to 3.58"
38.	90 92	43 43		BW1+1.29 BW1+1.78	to 5.72" to 3.93"
39.	98 100	43 43		BW1+2.86 BW1+2.12	to 5.07" to 3.58"
40.	126 128	43 43		BW1+1.64 BW1+1.10	to 4.91" to 5.34"

Attachment V.P.1

V.P.1-3

PDP pairs not associated with mid-span indications, column oriented, steam generator 21. ECT orientation is identified, if known.

				Associated PDP	
	Row	Col		From	To
41.	106 108	47 47		08H+31.76 08H+28.99	to 42.25" to 41.21"
42.	60 62	49 49		07H+29.51 07H+30.10	to 42.60" to 44.06"
43.	61 63	50 50		07H+35.77 07H+36.41	to 45.36" to 45.73"
44.	133 135	50 50		09H+16.46 09H+14.67	to 19.02" to 19.42"
Note: ECT orientation confirmed deposits on 133-50 and 135-50 were directly on column orientation, but did not confirm if they were facing toward or away from each other.					
45.	102 104	51 51		08H+27.49 08H+25.33	to 36.77" to 38.04"
46.	125 127	52 52		BW1+2.49 BW1+2.61	to 4.15" to 3.77"
47.	141 143	54 54		09H+19.19 09H+19.64	to 25.90" to 27.54"
48.	142 144	55 55		09H+21.60 09H+5.43	to 26.46" to 28.96"
49.	111 113	56 56		BW1+3.74 BW1+1.74	to 5.68" to 3.74"
50.	110 112	57 57		08H+36.50 08H+36.62	to 42.43" to 43.66"
51.	109 111	60 60		BW1+4.37 BW1+1.73	to 6.18" to 4.15"
52.	145 147	60 60		BW1+3.85 BW1+2.64	to 6.35" to 3.72"
53.	144 146 148	61 61 61		09H+22.41 09H+22.29 09H+20.55	to 28.42" to 29.26" to 30.47"
54.	119 121	62 62		BW1+4.49 BW1+2.33	to 5.62" to 3.97"

Attachment V.P.1					
V.P.1-3					
PDP pairs not associated with mid-span indications, column oriented, steam generator 21. ECT orientation is identified, if known.					
				Associated PDP	
	Row	Col		From	To
55.	147 147 149	62 62 62		09H+23.83 09H+26.82 09H+15.24	to 29.80" to 30.67" to 32.91"
56.	111 113	64 64		BW1+1.97 BW1+1.53	to 4.96" to 3.57"
57.	147 149	64 64		09H+26.15 09H+19.33	to 31.03" to 31.52"
58.	114 116	65 65		BW1+0.22 BW1+1.39	to 4.80" to 2.89"
59.	124 126	65 65		BW1+4.30 BW1+3.00	to 6.47" to 5.31"
60.	102 104	71 71		08H+31.84 08H+13.49	to 39.77" to 37.07"
61.	108 110	71 71		08H+20.42 08H+15.88	to 41.67" to 45.41"
62.	107 109	72 72		08H+18.35 08H+13.91	to 39.95" to 31.52"
63.	108 110	73 73		08H+28.31 08H+14.86	to 47.10" to 47.03"
64.	150 152	75 75		08H+7.68 08H+8.62	to 16.98" to 16.20"
Note: ECT orientation confirmed deposits on 150-75 and 152-75 were directly on column orientation, but did not confirm if they were facing toward or away from each other.					
65.	129 131	76 76		BW1+3.41 BW1+1.53	to 4.78" to 3.31"
66.	127 129	78 78		BW1+2.95 BW1+1.88	to 5.70" to 4.02"
67.	146 148	79 79		09H+23.33 09H+21.32	to 31.58" to 32.60"
Note: ECT orientation confirmed deposits on 146-79 land 148-79 were directly on column orientation, but did not confirm if they were facing toward or away from each other.					

Attachment V.P.1					
V.P.1-3					
PDP pairs not associated with mid-span indications, column oriented, steam generator 21. ECT orientation is identified, if known.					
				Associated PDP	
	Row	Col		From	To
68.	103 105	80 80		08H+29.60 08H+22.38	to 38.72" to 37.67"
69.	115 117	80 80		08H+27.15 08H+27.00	to 47.33" to 43.00"
Note: Based on ECT orientation, the deposit on 117-80 directly faced 115-80. The orientation of 115-80 was unknown.					
70.	137 139	80 80		BW1+2.09 BW1+1.86	to 5.15" to 3.47"
71.	115 117	82 82		08H+25.67 08H+18.95	to 41.77" to 41.57"
Note: Based on ECT orientation, the deposit on 117-82 directly faced 115-82. The orientation of 115-82 was unknown.					
72.	105 107 109	84 84 84		BW1+0.27 BW1+1.29 BW1+0.00	to 3.59" to 5.67" to 4.32"
73.	104 106	85 85		BW1+1.44 BW1+1.00	to 5.44" to 4.73"
74.	126 128	87 87		BW1+3.02 BW1+1.94	to 4.97" to 3.39"
75.	138 140	87 87		BW1+2.40 BW1+2.44	to 5.25" to 4.12"
76.	148 150	87 87		BW1+2.91 BW1+2.29	to 5.35" to 4.10"
77.	101 103	88 88		BW1-0.45 BW1+1.38	to 5.24" to 4.74"
78.	108 110	89 89		BW1-2.21 BW1+1.77	to 3.96" to 2.75"
79.	114 116	89 89		08H+14.95 08H+43.20	to 40.11" to 48.23"
Note: Based on ECT orientation, the deposit on 116-89 directly faced 114-89. The orientation of 114-89 was unknown.					

Attachment V.P.1					
V.P.1-3					
PDP pairs not associated with mid-span indications, column oriented, steam generator 21. ECT orientation is identified, if known.					
				Associated PDP	
	Row	Col		From	To
80.	146 148	89 89		09H+16.09 09H+17.86	to 31.23" to 32.20"
Note: ECT orientation confirmed deposits on 146-89 and 148-89 were directly on column orientation, but did not confirm if they were facing toward or away from each other.					
81.	157 159	90 90		08H+34.93 08H+30.90	to 40.61" to 37.82"
82.	157 159	90 90		09H+27.47 09H+28.57	to 37.41" to 38.72"
83.	100 102 104 106	91 91 91 91		BW1+1.71 BW1+1.42 BW1+2.37 BW1+1.51	to 4.95" to 3.81" to 7.24" to 5.35"
84.	136 138	91 91		BW1+3.22 BW1+2.61	to 5.80" to 4.39"
85.	101 103	92 92		BW1+2.11 BW1+1.80	to 4.45" to 3.30"
86.	157 159	92 92		09H+23.77 09H+26.96	to 37.83" to 39.59"
87.	104 106	93 93		BW1+2.82 BW1+1.99	to 7.47" to 4.37"
88.	100 102	95 95		BW1+2.36 BW1+1.38	to 4.84" to 3.57"
89.	106 108	95 95		BW1+1.67 BW1+0.04	to 4.72" to 3.92"
90.	124 126	95 95		BW1+4.23 BW1+2.75	to 6.18" to 4.68"
91.	65 67 69	96 96 96		07H+31.69 07H+30.09 07H+0.85	to 36.24" to 36.71" to 39.33"
92.	91 93	96 96		08H+15.53 08H+15.58	to 24.59" to 24.98"

Attachment V.P.1					
V.P.1-3					
PDP pairs not associated with mid-span indications, column oriented, steam generator 21. ECT orientation is identified, if known.					
				Associated PDP	
	Row	Col		From	To
93.	101 103	96 96		BW1+2.34 BW1+1.70	to 4.75" to 3.86"
94.	127 129	96 96		07H+1.05 07H+1.08	to 23.00" to 44.05"
95.	127 129	96 96		08H+1.11 08H+1.11	to 44.67" to 39.21"
96.	141 143	98 98		BW1+3.91 BW1+2.79	to 5.29" to 3.72"
97.	64 66	101 101		07H+23.83 07H+27.49	to 39.25" to 41.47"
98.	156 158 158	103 103 103		09H+30.02 09H+26.40 09H+34.63	to 42.94" to 42.66" to 42.49"
99.	155 157	106 106		09H+32.60 09H+26.29	to 40.89" to 42.46"
100.	110 112	107 107		BW1+5.39 BW1+7.48	to 7.24" to 9.04"
101.	109 111	108 108		BW1+2.52 BW1+1.25	to 4.24" to 2.61"
102.	145 147	108 108		BW1+2.39 BW1+3.39	to 3.05" to 2.86"
103.	151 153	114 114		BW1+2.04 BW1+2.97	to 2.96" to 4.31"
104.	150 152 154	115 115 115		09H+24.56 09H+27.92 09H+25.03	to 37.24" to 38.99" to 37.03"
105.	150 152	119 119		09H+30.12 09H+22.76	to 38.37" to 38.14"
106.	139 141	124 124		09H+17.61 09H+17.48	to 25.00" to 24.45"
Note: ECT orientation confirmed deposits on 139-124 and 141-124 were directly on column orientation, but did not confirm if they were facing toward or away from each other.					

Attachment V.P.1					
V.P.1-3					
PDP pairs not associated with mid-span indications, column oriented, steam generator 21. ECT orientation is identified, if known.					
				Associated PDP	
	Row	Col		From	To
107.	147 149	124 124		09H+17.91 09H+21.52	to 26.32" to 33.34"
108.	126 128	127 127		BW1+2.63 BW1+1.69	to 5.34" to 3.74"
109.	111 111 113	134 134 134		08H+29.39 08H+29.40 08H+29.69	to 42.64" to 42.09" to 41.53"
110.	125 127	134 134		BW1+3.41 BW1+2.41	to 5.04" to 3.65"
N/A.	1 3	136 136		TSH+2.62 TSH+5.06	to 11.81" to 7.11"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.					
N/A	1 3	138 138		TSH+2.31 TSH+1.79	to 11.24" to 9.21"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.					
N/A	2 4	139 139		TSH+2.07 TSH+4.25	to 7.51" to 8.56"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.					
111.	115 117 117	140 140 140		08H+42.49" 09H+0.49 08H+43.06	to 45.80" to 3.42" to 45.79"
Note: Based on ECT orientation, the deposit on 117-140 directly faced 115-140. 115-80 was column oriented, but did not confirm if it was directly toward or away from 117-140.					
N/A	4 6 8 10	143 143 143 143		TSH+3.13 TSH+3.20 TSH+3.81 TSH+5.63	to 9.39" to 10.11" to 9.31" to 8.41"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.					

Attachment V.P.1

V.P.1-3

PDP pairs not associated with mid-span indications, column oriented, steam generator 21. ECT orientation is identified, if known.

				Associated PDP	
	Row	Col		From	To
112.	94 96	143 143		BW1+3.01 BW1+2.83	to 5.33" to 4.15"
113.	100 102	143 143		BW1+3.18 BW1+2.77	to 5.95" to 4.98"
N/A	5 7 9 11	144 144 144 144		TSH+3.17 TSH+3.90 TSH+5.50 TSH+5.47	to 9.74" to 9.23" to 8.86" to 7.40"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.					
114.	97 99	144 144		BW1+2.64 BW1+1.67	to 4.48" to 3.08"
115.	99 101 103	144 144 144		BW1+2.18 BW1+3.02 BW1+1.44	to 3.22" to 4.75" to 3.12"
116.	124 126	147 147		BW1+3.72 BW1+2.08	to 5.86" to 4.28"
117.	110 112	149 149		BW1+2.42 BW1+1.83	to 5.55" to 4.15"
118.	104 106	151 151		08H+19.99 08H+14.61	to 32.84" to 28.17"
Note: ECT orientation confirmed deposits on 104-151 and 106-151 were directly on column orientation, but did not confirm if they were facing toward or away from each other.					
119.	103 105	152 152		BW1+3.22 BW1+2.60	to 5.06" to 3.84"
120.	113 115	152 152		08H+41.63 08H+37.39	to 47.94" to 48.85"
Note: ECT orientation confirmed deposits on 113-152 and 115-152 were directly on column orientation, but did not confirm if they were facing toward or away from each other.					
121.	60 62	153 153		BW1+2.62 BW1-0.18	to 4.40" to 3.37"

Attachment V.P.1					
V.P.1-3					
PDP pairs not associated with mid-span indications, column oriented, steam generator 21. ECT orientation is identified, if known.					
				Associated PDP	
	Row	Col		From	To
122.	111 113 115	154 154 154		BW1+2.81 BW1+2.34 BW1+2.10	to 5.16" to 6.29" to 4.47"
123.	55 57	156 156		BW1+2.92 BW1+1.77	to 5.25" to 3.66"
124.	103 105	156 156		08H+28.00 08H+27.30	to 31.52" to 32.50"
Note: ECT orientation confirmed deposits on 103-156 and 105-156 were directly on column orientation, but did not confirm if they were facing toward or away from each other.					
125.	111 113	156 156		BW1+2.66 BW1+2.34	to 4.67" to 5.44"
126.	104 106	157 157		08H+22.27 08H+22.81	to 32.10" to 33.53"
Note: ECT orientation confirmed deposits on 104-157 and 106-157 were directly on column orientation, but did not confirm if they were facing toward or away from each other.					
127.	115 117	158 158		08H+24.88 08H+20.49	to 37.52" to 34.94"
128.	106 108	159 159		BW1+2.58 BW1+2.65	to 5.50" to 4.30"
129.	63 65	160 160		BW1+2.66 BW1+2.28	to 5.25" to 3.77"
130.	101 103	160 160		BW1+3.44 BW1+2.00	to 5.54" to 3.13"
131.	98 100	161 161		BW1+2.56 BW1+1.84	to 5.20" to 4.15"
132.	95 97 99	162 162 162		BW1+0.70" BW1+2.08 BW1+1.81	to 4.05" to 5.33" to 4.01"
133.	104 106	165 165		08H+25.11 08H+22.08	to 31.49" to 31.37"
Note: ECT orientation confirmed deposits on 104-165 and 106-165 were directly on column orientation, but did not confirm if they were facing toward or away from each other.					

Attachment V.P.1					
V.P.1-3					
PDP pairs not associated with mid-span indications, column oriented, steam generator 21. ECT orientation is identified, if known.					
				Associated PDP	
	Row	Col		From	To
134.	78 80	175 175		08H+11.88 08H+5.67	to 13.77" to 20.56"
135.	30 32	177 177		07H+14.06 07H+11.66	to 18.62" to 18.81"
136.	68 70	177 177		08H+1.24 08H+1.26	to 4.01" to 2.74"
137.	41 43	180 180		BW1+4.23 BW1+3.99	to 18.66" to 18.18"

Attachment V.P.1				
V.P.1-3				
PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 21 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit). ECT orientation is indicated, if known.				
				Associated PDP
	Row	Col		From To
1.	31 30	6 7		07H+1.25 to 3.14" 07H+1.53 to 2.64"
2.	63 62 64	16 17 * 17 *		07H+33.62 to 46.92" 07H+32.68 to 45.25" 07H+32.25 to 44.34"
3.	21 22	20 21		07H+1.04 to 2.12" 07H+1.28 to 2.39"
4.	91 90 92	20 21 * 21 *		BW1+3.44 to 5.73" BW1+2.14 to 5.23" BW1+0.41 to 3.80"
5.	36 35	25 26 *		07H+1.27 to 3.13" 07H+1.9 to 2.78"
6.	112 111	29 30 *		BW1+1.27 to 4.19" BW1+2.89 to 4.31"
N/A	116 117 116 116	31* 32 33 * 33 *		08H+16.53 to 38.77" 08H+25.87 to 40.71" 08H+26.87 to 40.76" 08H+27.09 to 40.90
Note: Although located at the same height, ECT orientation indicated that deposits on 116-31, 117-32, and 116-33 were column oriented, and not facing each other.				
N/A	114 113 114	31* 32 33 *		08H+16.38 to 40.51" 08H+28.33 to 40.97" 08H+26.71 to 40.35"
Note: Although located at the same height, ECT orientation indicated that deposits on 113-32 and 114-33 were column oriented, and not facing each other.				
7.	109 111 110	32* 32* 33		BW1+2.37 to 5.06" BW1+2.81 to 6.11" BW1+1.93 to 5.91"
8.	116 116 117	33 * 33 * 34		08H+26.87 to 40.76" 08H+27.09 to 40.90" 08H+26.54 to 38.45"

Attachment V.P.1				
V.P.1-3				
PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 21 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit). ECT orientation is indicated, if known.				
				Associated PDP
	Row	Col		From To
9.	57 56	34 35		07H+1.54 to 2.03" 07H+1.62 to 2.40"
10.	67 66	34 35		07H+4.46 to 42.85" 07H+1.06 to 38.32"
N/A	104 105	37 38		08H+19.72 to 20.60" 08H+4.54 to 39.11"
Note: Although located at the same height, ECT orientation indicated that deposits on 104-37 and 105-38 were column oriented, and not facing each other.				
11.	129 128	40 41		09H+4.88 to 15.61" 09H+6.07 to 14.50"
N/A	129 130 131	40 41 42		08H+36.38 to 43.07" 08H+20.31 to 43.26" 08H+26.78 to 42.50"
Note: Although located at the same height, ECT orientation indicated that deposits on 130-41 and 131-42 were column oriented, and not facing each other.				
N/A	6 7 8	49 50 51		TSH+2.26 to 6.02" TSH+2.08 to 3.35" TSH+1.54 to 3.44"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.				
12.	141 142 141 143	52 53 54 * 54 *		09H+21.32 to 26.74" 09H+4.97 to 26.50" 09H+19.19 to 25.90" 09H+19.64 to 27.54"
13.	111 110	56 * 57		BW1+3.74 to 5.68" BW1+1.63 to 4.47"
14.	145 146 147 146 148	58 59 60 61 * 61 *		09H+20.14 to 29.46" 09H+19.98 to 30.21" 09H+28.37 to 30.39" 09H+22.29 to 29.26" 09H+20.55 to 30.47"

Attachment V.P.1				
V.P.1-3				
PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 21 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit). ECT orientation is indicated, if known.				
				Associated PDP
	Row	Col		From To
15.	147 147 149 148 147 149	62 * 62 * 62 * 63 64 * 64 *		09H+23.83 to 29.80" 09H+26.82 to 30.67" 09H+15.24 to 32.91" 09H+23.18 to 31.89" 09H+26.15 to 31.03" 09H+19.33 to 31.52"
16.	151 150	66 67		09H+25.72 to 34.06" 09H+6.3 to 33.76"
17.	148 147 149 148	75 76 * 76 * 77		09H+27.94 to 32.56" 09H+20.39 to 31.37" 09H+23.9 to 31.86" 09H+26.87 to 32.35"
18.	139 138 137 139 138	78 79 80 * 80 * 81		BW1+2.91 to 4.64" BW1+2.59 to 5.60" BW1+2.09 to 5.15" BW1+1.86 to 3.47" BW1+2.76 to 5.69"
N/A	117 118 117 118	80 * 81 82 * 83		08H+27.00 to 43.00" 08H+25.57 to 42.82" 08H+18.95 to 41.57" 08H+21.68 to 24.22"
Note: Although located at the same height, ECT orientation indicated that deposits on 117-80, 118-81, and 117-82 were column oriented, and not facing each other.				
19.	155 156 157	82 83 84		BW1+0.68 to 2.91" BW1+2.86 to 5.99" BW1+2.42 to 3.59"
20.	115 116	86 87		08H+11.77 to 16.97" 08H+16.18 to 21.59"
21.	159 158	86 87		09H+4.30 to 41.67" 09H+28.58 to 40.41"
22.	100 101	87 88		BW1+1.43 to 3.73" BW1-0.45 to 5.24"

Attachment V.P.1

V.P.1-3

PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 21 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit). ECT orientation is indicated, if known.

				Associated PDP
	Row	Col		From To
23.	115	88		08H+23.04 to 44.48"
	114	89 *		08H+14.95 to 40.11"
	114	89		08H+24.16 to 39.23"
	116	89 *		08H+43.20 to 48.23"
24.	158	89		09H+6.63 to 12.8"
	157	90		08H+49.2 to 54.94"
	158	91		09H+6.5 to 13.3"
	157	92		09H+5.15 to 13.92"
25.	158	87		08H+35.10 to 43.02"
	159	88		08H+39.41 to 45.66"
	158	89		08H+33.49 to 42.98"
	157	90 *		08H+34.93 to 40.61"
	159	90 *		08H+30.90 to 37.82"
	158	91		08H+32.51 to 40.55"
	159	92		08H+24.89 to 37.89"
26.	158	87		09H+28.58 to 40.41"
	159	88		09H+37.53 to 46.73"
	158	89		09H+32.76 to 41.20"
	157	90 *		09H+27.47 to 37.41"
	159	90 *		09H+28.57 to 38.72"
	158	91		90H+27.59 to 38.96"
	157	92 *		09H+23.77 to 37.83"
	159	92 *		09H+26.96 to 39.59"
	156	93		09H+29.00 to 40.99"
	157	94		09H+32.33 to 40.35"
27.	105	90		BW1+3.53 to 4.49"
	104	91 *		BW1+2.37 to 7.24"
	106	91 *		BW1+1.51 to 5.35"
28.	104	91 *		BW1+2.37 to 7.24"
	106	91 *		BW1+1.51 to 5.35"
	107	92		BW1+2.14 to 4.58"
29.	107	92		BW1+2.14 to 4.58
	104	93 *		BW1+2.82 to 7.47"
	106	93 *		BW1+1.99 to 4.37"

Attachment V.P.1					
V.P.1-3					
PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 21 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit). ECT orientation is indicated, if known.					
				Associated PDP	
	Row	Col	-	From	To
30.	110 109 108	93 94 95 *		BW1+0.86 to 4.09" BW1+2.06 to 3.77" BW1+0.04 to 3.92"	
31.	126 127	95 96		08H+1.17 to 44.00" 08H+1.11 to 44.67"	
32.	130 129	95 96		09H+1.15 to 2.00" 09H+1.14 to 2.22"	
33.	101 100	96 * 97		BW1+2.34 to 4.75" BW1+0.71 to 3.86"	
34.	102 103	99 100		BW1+2.13 to 4.27" BW1+2.32 to 4.30"	
35.	106 107 106	99 100 101		BW1+2.35 to 7.99" BW1+2.56 to 3.87" BW1-1.49 to 3.60"	
36.	158 157	99 100		09H+23.87 to 42.80" 09H+27.60 to 40.53"	
N/A	154 155 156	101 102 103 *		09H+35.34 to 42.53" 09H+39.48 to 45.18" 09H+30.02 to 42.94"	
Note: Although located at the same height, ECT orientation indicated that deposits on 154-101 and 155-102 were column oriented, and not facing each other.					
37.	100 101	105 106		BW1+3.20 to 6.27" BW1+2.60 to 4.50"	
38.	148 145 147 144	107 108* 108* 109		BW1+2.58 BW1+2.39 BW1+3.39 BW1+6.61	to 3.72" to 3.05" to 2.86" to 8.40"
39.	152 153 154	115 * 116 115 *		09H+27.92 to 38.99" 09H+25.24 to 38.22" 09H+25.03 to 37.03"	

Attachment V.P.1				
V.P.1-3				
PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 21 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit). ECT orientation is indicated, if known.				
				Associated PDP
	Row	Col		From To
40.	153 152 153	118 119 * 120		09H+27.13 to 37.24" 09H+22.76 to 38.14" 09H+34.68 to 38.69"
41.	141 141 142	128 128 129		BW1+2.78 to 5.09" BW1+2.89 to 5.05" BW1+2.44 to 3.51"
N/A	3 4 3	136 * 137 138 *		TSH+5.06 to 7.11" TSH+5.58 to 8.83" TSH+1.79 to 9.21"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.				
N/A	2 1	139 * 140		TSH+2.07 to 7.51" TSH+2.57 to 11.50"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.				
N/A	4 5 6	143 * 142 143 *		TSH+3.13 to 9.39" TSH+3.14 to 9.81" TSH+3.20 to 10.11"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.				
42.	97 96	142 143 *		BW1+3.16 to 4.38" BW1+2.83 to 4.15"
43.	112 113	149 * 150		BW1+1.83 to 4.15" BW1+3.04 to 5.29"
44.	130 129	149 150		08H+27.93 to 39.02" 08H+34.71 to 41.02"
45.	103 105 104	152 * 152 * 153		BW1+3.22 to 5.06" BW1+2.60 to 3.84" BW1+3.95 to 5.83"
46.	112 111 113	153 154 * 154 *		BW1+2.43 to 4.41" BW1+2.81 to 5.16" BW1+2.34 to 6.29"

Attachment V.P.1					
V.P.1-3					
PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 21 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit). ECT orientation is indicated, if known.					
					Associated PDP
	Row	Col			From To
47.	115 116 117	158 * 157 158 *			08H+24.88 to 37.52" 08H+36.23 to 40.64" 08H+20.49 to 34.94"
48.	82 81	161 162			BW1+1.57 to 3.88" BW1+2.00 to 4.51"

Attachment V.P.1

V.P.1-4

Mid-span axial indications, steam generator 22

					Associated PDP
	Row	Col	Location	Length	From To
1.	112	39	08H+29.38"	0.72"	08H+24.69 to 36.4"
2.	115	40	08H+40.62"	0.38"	08H+34.27 to 43.6"
3.	115	40	BW1+3.63"	2.17"	not aligned w/deposit
4.	117	40	08H+40.89"	0.21"	08H+38.00 to 51+"
Note: Although ECT did not identify a PDP at the 117-40 flaw, examination in the laboratory confirmed the presence of a deposit.					
5.	110	41	BW1+5.07"	0.53"	BW1+4.27 to 5.8"
6.	115	42	08H+39.44"	0.16"	08H+31.59 to 43.1"
7.	117	42	08H+49.08"	0.32"	08H+35.12 to 44.1" 08H+36.53 to 43.45"
8.	117	42	08H+41.88"	0.32"	08H+35.12 to 44.1" 08H+36.53 to 43.45"
9.	113	44	BW1+4.12"	0.78"	BW1+4.29 to 5.0"
10.	115	46	BW1+5.28"	0.82"	not aligned w/deposit
11.	124	49	BW1+8.71"	0.99"	not aligned w/deposit
12.	117	52	BW1+8.84"	1.02"	not aligned w/deposit
13.	109	54	BW1+4.57"	0.83"	not aligned w/deposit
14.	114	55	BW1+4.22"	0.99"	BW1+1.40 to 5.42"
15.	113	56	BW1+3.69"	0.71"	BW1+3.58 to 4.4"
16.	132	57	BW1+0.05"	0.24"	BW1+0.16 to 1.23"
17.	142	83	BW1+18.35"	2.75"	not aligned w/deposit
18.	140	87	BW1+19.24"	0.96"	not aligned w/deposit
19.	146	89	BW1+2.74"	0.96"	BW1+2.07 to 4.3"
20.	128	91	BW1+6.61"	1.65"	BW1+6.79 to 7.83"
21.	131	92	09H+16.14"	0.36"	not aligned w/deposit
22.	126	93	BW1+7.15"	1.05"	not aligned w/deposit

Attachment V.P.1					
V.P.1-4					
Mid-span axial indications, steam generator 22					
					Associated PDP
	Row	Col	Location	Length	From To
23.	132	93	BW1+7.90"	0.60"	not aligned w/deposit
24.	138	93	BW1+2.79"	2.41"	not aligned w/deposit
25.	146	93	BW1+3.61	0.39"	BW1+1.52 to 4.2"
26.	125	94	08H+24.69	1.31"	08H+15.63 to 34.83"
27.	125	94	08H+30.47"	1.43"	08H+15.63 to 34.83"
28.	125	94	08H+38.55"	1.25"	not aligned w/deposit
29.	125	94	BW1+6.64"	0.56"	not aligned w/deposit
30.	127	94	BW1+5.91"	2.39"	not aligned w/deposit
31.	137	94	BW1+18.86"	0.44"	not aligned w/deposit
32.	127	96	08H+13.96"	0.94"	not aligned w/deposit
33.	127	96	08H+33.46"	0.54"	not aligned w/deposit
34.	127	96	08H+39.66"	0.24	not aligned w/deposit
35.	127	96	08H+40.98"	0.62"	not aligned w/deposit
36.	127	96	BW1+2.35"	0.45"	not aligned w/deposit
37.	127	96	BW1+3.92"	2.38"	not aligned w/deposit
38.	129	96	BW1+2.86"	0.54"	not aligned w/deposit
39.	129	96	BW1+5.80"	1.80"	not aligned w/deposit
40.	129	98	BW1+4.08"	1.22"	BW1+3.95 to 20.00"
41.	129	98	BW1+6.62"	0.78"	BW1+3.95 to 20.00"
42.	142	99	BW1+3.53"	0.57"	not aligned w/deposit
43.	144	99	BW1+4.55"	2.55"	not aligned w/deposit
44.	150	99	BW1+18.38"	1.27"	not aligned w/deposit
45.	135	102	BW1+1.45"	0.55"	not aligned w/deposit
46.	135	102	BW1+6.19"	0.41"	not aligned w/deposit
47.	147	102	BW1+7.83"	3.07"	BW1+6.42 to 30.31"
48.	147	102	BW1+13.45"	0.45"	BW1+6.42 to 30.31"

Attachment V.P.1					
V.P.1-4					
Mid-span axial indications, steam generator 22					
					Associated PDP
	Row	Col	Location	Length	From To
49.	147	102	BW1+18.88"	0.92"	BW1+6.42 to 30.31"
50.	133	104	BW1+1.89"	0.71"	not aligned w/deposit
51.	134	105	BW1+1.10"	1.00"	not aligned w/deposit
52.	134	111	09H+20.47"	0.63"	09H+14.15 to 21.3"
53.	144	115	09H+25.89"	0.31"	09H+24.55 to 43.5"
54.	144	115	09H+27.70"	0.50"	09H+24.55 to 43.5"
55.	144	115	09H+32.34"	0.56"	09H+24.55 to 43.5"
56.	146	115	09H+22.95"	7.35"	09H+20.82 to 31.2"
57.	150	115	09H+24.46"	7.24"	09H+19.51 to 34.1"
58.	143	116	BW1+3.5"	0.50"	not aligned w/deposit
59.	145	116	BW1+6.42"	0.28"	not aligned w/deposit
60.	134	117	09H+14.20"	1.19"	09H+12.74 to 19.9"
61.	140	117	BW1+2.63"	0.47"	BW1+2.03 to 3.0"
62.	145	118	09H+28.91"	1.09"	09H+27.01 to 31.2"
63.	140	119	09H+22.99"	0.21"	09H+19.55 to 27.2"
64.	142	119	09H+20.75"	3.95"	09H+20.13 to 27.7"
65.	142	119	BW1+4.94"	0.26"	not aligned w/deposit
66.	139	122	BW1+3.77"	0.43"	BW1+2.53 to 4.6"
67.	141	124	BW1+2.86"	0.58"	BW1+0.90 to 3.58"
68.	132	133	BW1+3.60"	0.90"	not aligned w/deposit
69.	136	133	BW1+7.59"	0.81"	not aligned w/deposit
70.	142	133	BW1+15.53"	0.17"	not aligned w/deposit
71.	128	135	BW1+5.39"	0.88"	not aligned w/deposit
72.	132	135	BW1+6.92"	0.39"	not aligned w/deposit
73.	129	136	BW1+6.96"	0.74"	not aligned w/deposit
74.	131	136	09H+17.87"	0.13"	09H+14.55 to 18.5"

Attachment V.P.1						
V.P.1-4						
Mid-span axial indications, steam generator 22						
					Associated PDP	
	Row	Col	Location	Length	From	To
75.	137	136	BW1+16.93"	0.77"	not aligned w/deposit	
76.	139	136	BW1+15.18"	0.32"	not aligned w/deposit	
77.	117	144	08H+34.34"	9.16"	08H+28.53 to 43.4"	
78.	123	144	BW1+5.60"	0.60"	not aligned w/deposit	
79.	107	150	BW1+3.57"	0.31"	BW1+2.51 to 4.49"	
80.	103	156	08H+16.39"	2.83"	08H+14.38 to 25.50" 08H+16.56 to 28.9"	
81.	105	156	08H+19.64"	1.36"	08H+13.87 to 31.41" 08H+16.74 to 37.3"	
82.	105	156	08H+21.54"	4.08"	08H+13.87 to 31.41" 08H+16.74 to 37.3"	
83.	105	156	08H+26.26"	4.39"	08H+13.87 to 31.41" 08H+16.74 to 37.3"	
84.	107	156	08H+24.68"	0.12"	08H+21.20 to 34.4"	
85.	100	157	BW1+2.13"	1.17"	BW1+1.47 to 3.2"	
86.	104	157	08H+24.59"	3.41"	08H+17.72 to 30.5"	
87.	93	160	08H+19.11"	0.19"	08H+17.92 to 22.6"	

Attachment V.P.1

V.P.1-5

PDP pairs associated with mid-span axial indications, steam generator 22

					Associated PDP	
	Row	**Col**	**Location**	**Length**	**From**	**To**
1.	112 114	39 39	08H+29.38"	0.72"	08H+24.69 to 36.4" 08H+24.52 to 36.2"	
2.	115 117	40 40	08H+40.62"	0.38"	08H+34.27 to 43.6" 08H+38.00 to 51+"	
3.	115 117	40 40	08H+40.89"	0.21"	08H+34.27 to 43.6" 08H+38.00 to 51+"	
Note: Based on ECT analysis of 115-40 & 117-40, ECT orientation results on 115-40 & 117-40, and visual orientation of the 117-40 deposit in the laboratory, the two flaws were facing each other at the same height, and both were under a bridged deposit. The bridged deposit was confirmed from the videotape of the 116-41 location.						
4.	110 112	41 41	BW1+5.07"	0.53"	BW1+4.27 to 5.8" BW1+2.60 to 4.2"	
5.	115 117	42 42	08H+39.44"	0.16"	08H+31.59 to 43.1" 08H+35.12 to 44.1" 08H+36.53 to 43.45"	
6.	115 117	42 42	08H+49.08"	0.32"	08H+31.59 to 43.1" 08H+35.12 to 44.1" 08H+36.53 to 43.45"	
7.	115 117	42 42	08H+41.88"	0.32"	08H+31.59 to 43.1" 08H+35.12 to 44.1" 08H+36.53 to 43.45"	
Note: Based on ECT analysis and ECT orientation results on 115-42 & 117-42, the two flaws were facing each other at the same height, and both were under a bridged deposit. The bridged deposit was confirmed from the videotape of the 116-41 location.						
8.	114 113 115	55 56 56	BW1+4.22"	0.99"	BW1+1.40 to 5.42" BW1+3.58 to 4.4" BW1+2.93 to 15.60"	
9.	114 113 115	55 56 56	BW1+3.69"	0.71"	BW1+1.40 to 5.42" BW1+3.58 to 4.4" BW1+2.93 to 15.60"	
N/A	125 127	94 94	BW1+6.64"	0.56"	not aligned w/deposit flaw @ BW1+5.91"	

Attachment V.P.1

V.P.1-5						
PDP pairs associated with mid-span axial indications, steam generator 22						
					Associated PDP	
	Row	**Col**	**Location**	**Length**	**From**	**To**
N/A	125 127	94 94	BW1+5.91"	2.39"	flaw @ BW1+6.64" not aligned w/deposit	
Note: Although neither the 125-94 or 127-94 tube had a deposit identified, the existence of adjacent flaws at the same approximate height is noteworthy as a possible sign of a bridged deposit.						
N/A	127 129	96 96	BW1+2.35"	0.45"	not aligned w/deposit flaw @ BW1+2.86"	
N/A	127 129	96 96	BW1+3.92"	2.38"	not aligned w/deposit flaw @ BW1+2.86"	
N/A	127 129	96 96	BW1+2.86"	0.54"	flaw @ BW1+3.92" not aligned w/deposit	
N/A	127 129	96 69	BW1+5.80"	1.80"	flaw @ BW1+3.92" not aligned w/deposit	
Note: Although neither the 127-96 or 129-96 tube had a deposit identified, the existence of adjacent flaws at the same approximate height is noteworthy as a possible sign of a bridged deposit.						
10.	129 131	98 98	BW1+4.08"	1.22"	BW1+3.95 to 20.00" BW1+1.90 to 2.8"	
11.	129 131	98 98	BW1+6.62"	0.78"	BW1+3.95 to 20.00" BW1+1.90 to 2.8"	
12.	140 142	99 99	BW1+3.53"	0.57"	BW1+2.14 to 2.9" not aligned w/deposit	
N/A	142 144	99 99	BW1+4.55"	2.55"	flaw @ BW1+3.53" not aligned w/deposit	
Note: Although neither the 142-99 or 144-99 tube had a deposit identified, the existence of adjacent flaws at the same approximate height is noteworthy as a possible sign of a bridged deposit.						
13.	133 134	104 105	BW1+1.89"	0.71"	not aligned w/deposit flaw @ BW1+1.10"	

Attachment V.P.1

V.P.1-5

PDP pairs associated with mid-span axial indications, steam generator 22

					Associated PDP	
	Row	Col	Location	Length	From	To
14.	133 134	104 105	BW1+1.10	1.00"	flaw @ BW1+1.89" not aligned w/deposit	
Note: Although neither the 133-104 or 134-105 tube had a deposit identified, the existence of adjacent flaws at the same approximate height is noteworthy as a possible sign of a bridged deposit.						
15.	144 146	115 115	09H+25.89"	0.31"	09H+24.55 to 34.5" 09H+20.82 to 31.2"	
16.	144 146	115 115	09H+27.70"	0.50"	09H+24.55 to 34.5" 09H+20.82 to 31.2"	
17.	144 146	115 115	09H+32.34"	0.56"	09H+24.55 to 34.5" 09H+20.82 to 31.2"	
18.	144 146 148	115 115 115	09H+22.95"	7.35"	09H+24.55 to 34.5" 09H+20.82 to 31.2" 09H+21.48 to 33.3"	
19.	148 150 152	115 115 115	09H+24.46"	7.24"	09H+21.48 to 33.3" 09H+19.51 to 34.1" 09H+18.99 to 31.1"	
N/A	143 145	116 116	BW1+3.5"	0.50"	not aligned w/deposit flaw @ BW1+6.42"	
N/A	143 145	116 116	BW1+6.42"	0.28"	flaw @ BW1+3.5" not aligned w/deposit	
Note: Although neither the 143-116 or 145-116 tube had a deposit identified, the existence of adjacent flaws at the same approximate height is noteworthy as a possible sign of a bridged deposit.						
20.	145 147	118 118	09H+28.91"	1.09"	09H+27.01 to 31.2" 09H+20.71 to 31.5"	
21.	140 142	119 119	09H+22.99"	0.21"	09H+19.55 to 27.2" 09H+20.13 to 27.7"	
22.	140 142	119 119	09H+20.75"	3.95"	09H+19.55 to 27.2" 09H+20.13 to 27.7"	
Note: Based on ECT analysis and ECT orientation results on 140-119 & 142-119, the two flaws were facing each other at the same height, and both were under deposits, presumably a bridged deposit.						

Attachment V.P.1						
V.P.1-5						
PDP pairs associated with mid-span axial indications, steam generator 22						
					Associated PDP	
	Row	Col	Location	Length	From	To
23.	139 141	122 122	BW1+3.77"	0.43"	BW1+2.53 to 4.6" BW1+1.70 to 3.8"	
24.	136 135	133 134	BW1+7.59"	0.81"	not aligned w/deposit BW1+0.08 to 2.5"	
N/A	128 129	135 136	BW1+5.39"	0.88"	not aligned w/deposit flaw @ BW1+6.96"	
N/A	128 129	135 136	BW1+6.96"	0.74"	flaw @ BW1+5.39" not aligned w/deposit	
Note: Although neither the 128-135 or 129-136 tube had a deposit identified, the existence of adjacent flaws at the same approximate height is noteworthy as a possible sign of a bridged deposit. Based on ECT Orientation results, both 128-135 and 129-136 were oriented 60° from a batwing, thus it is likely that this is a flaw "pair."						
25.	131 133	136 136	09H+17.87"	0.13"	09H+14.55 to 18.5" 09H+14.10 to 18.8"	
N/A	137 139	136 136	BW1+16.93"	0.77"	not aligned w/deposit flaw @ BW1+15.18	
N/A	137 139	136 136	BW1+15.18"	0.32"	flaw @ BW1+16.93" not aligned w/deposit	
Note: Although neither the 137-136 or 139-136 tube had a deposit identified, the existence of adjacent flaws at the same approximate height is noteworthy as a possible sign of a bridged deposit.						
26.	115 117	144 144	08H+34.34"	9.16"	08H+29.30 to 33.9" 08H+28.53 to 43.4"	
Note: Based on ECT analysis and ECT orientation results on 115-144 and 117-144, the two flaws were facing each other at the same height, and both were under a bridged deposit. The bridged deposit was confirmed on videotape from the matching flat spot which remained on the 115-144 tube when viewed from the 117-144 location.						
27.	103 103 105 105 104	156 156 156 156 157	08H+16.39"	2.83"	08H+14.38 to 25.50" 08H+16.56 to 28.9" 08H+13.87 to 31.41" 08H+16.74 to 37.3" 08H+17.72 to 30.5"	

Attachment V.P.1

V.P.1-5

PDP pairs associated with mid-span axial indications, steam generator 22

	Row	Col	Location	Length	Associated PDP From	To
28.	103 103 105 105 107 104	156 156 156 156 156 157	08H+19.64"	1.36"	08H+14.38 to 25.50" 08H+16.56 to 28.9" 08H+13.87 to 31.41" 08H+16.74 to 37.3" 08H+21.20 to 34.4" 08H+17.72 to 30.5"	
29.	103 103 105 105 107 104	156 156 156 156 156 157	08H+21.54"	4.08"	08H+14.38 to 25.50" 08H+16.56 to 28.9" 08H+13.87 to 31.41" 08H+16.74 to 37.3" 08H+21.20 to 34.4" 08H+17.72 to 30.5"	
30.	103 103 105 105 107 104	156 156 156 156 156 157	08H+26.26"	4.39"	08H+14.38 to 25.50" 08H+16.56 to 28.9" 08H+13.87 to 31.41" 08H+16.74 to 37.3" 08H+21.20 to 34.4" 08H+17.72 to 30.5"	
31.	105 105 107	156 156 156	08H+24.68"	0.12"	08H+13.87 to 31.41" 08H+16.74 to 37.3" 08H+21.20 to 34.4	
32.	103 103 105 105 104	156 156 156 156 157	08H+24.59"	3.41"	08H+14.38 to 25.50" 08H+16.56 to 28.9" 08H+13.87 to 31.41" 08H+16.74 to 37.3" 08H+17.72 to 30.5"	

Note: Based on ECT analysis and ECT orientation results on 103-156, 105-156, 107-156, and 104-157: The flaws on 105-156 and 107-156 were facing each other at the same height, and both were under deposits, presumably a bridged deposit. The deposits on 103-156 and 105-156 were facing each other at the same height and the flaw on 105-156 faces 103-156, but although the direction of the flaw on 103-156 was unknown, a bridging deposit is still presumed. The deposit and flaw on 104-157 faces directly into the bridge between 103-156 and 105-156 suggesting the possibility of a three-way deposit bridge. The videotape confirmed a flat spot in the 104-147 tube which had been bridged to 105-156.

	Row	Col	Location	Length	Associated PDP From	To
33.	91 93	160 160	08H+19.11"	0.19"	08H+19.43 to 23.8" 08H+17.92 to 22.6"	

Attachment V.P.1				
V.P.1-6				
PDP pairs not associated with mid-span indications, column oriented, steam generator 22				
				Associated PDP
	Row	**Col**		**From To**
1.	58 58 60	9 9 9		07H+30.77 to 42.7" 07H+32.55 to 44.08" 07H+32.21 to 43.87"
2.	39 41	10 10		BW1-6.30 to +3.3" 07H+21.97 to 25.2"
3.	53 55	10 10		07H+21.45 to33.0" 07H+21.18 to 32.9"
4.	61 63	18 18		BW1+2.79 to 5.2" BW1+2.44 to 3.7"
5.	117 119	36 36		08H+42.18 to 43.1" 08H+37.46 to 43.6"
6.	64 66	45 45		07H+25.10 to 35.7" 07H+33.93 to 43.1"
7.	64 66	47 47		07H+24.40 to 35.0" 07H+32.34 to 48.5"
8.	68 70	47 47		07H+1.10 to 2.1" 07H+1.71 to 2.4"
9.	112 114	55 55		BW1+3.55 to 4.1" BW1+1.40 to 5.42"
10.	113 115	56 56		BW1+3.58 to 4.4" BW1+2.93 to 15.60"
11.	143 145	56 56		09H+25.88 to 28.8" 09H+24.61 to 27.8"
12.	101 103	58 58		BW1+3.75 to 5.8" BW1+2.56 to 4.6"
13.	111 113	58 58		08H+25.16 to 39.3" 08H+25.28 to 39.4"
14.	139 141 143 145	68 68 68 68		09H+22.61 to 26.3" 09H+24.23 to 28.0" 09H+21.04 to 31.0" 09H+20.55 to 32.1"

Attachment V.P.1				
V.P.1-6				
PDP pairs not associated with mid-span indications, column oriented, steam generator 22				
				Associated PDP
	Row	**Col**		**From To**
15.	126 128	69 69		BW1+6.06 to 6.3" BW1+6.18 to 6.3"
16.	143 145	70 70		BW1+4.08 to 4.5" BW1+2.49 to 3.2"
17.	132 134	71 71		BW1+2.51 to 5.0" BW1+1.89 to 3.7"
18.	116 118	75 75		08H+10.93 to 43.8" 08H+13.81 to 42.6"
19.	116 118	77 77		08H+11.52 to 42.6" 08H+13.93 to 43.6"
20.	124 126	79 79		BW1+2.64 to 6.2" BW1+2.08 to 4.3"
21.	121 123	80 80		BW1+1.95 to 5.3" BW1+1.48 to 4.0"
22.	139 141	80 80		BW1+3.99 to 5.0" BW1+2.10 to 3.3"
23.	155 157	80 80		09H+3.32 to 38.6" 09H+4.80 to 40.8"
24.	116 118	81 81		08H+13.88 to 41.4" 08H+14.82 to 42.6"
25.	146 148	81 81		BW1+2.95 to 4.8" BW1+2.57 to 3.6"
26.	155 157	82 82		09H+1.89 to 39.1" 09H+28.33 to 41.2"
27.	156 158	83 83		09H+5.81 to 40.2" 09H+19.58 to 41.8"
28.	147 149	84 84		BW1+0.09 to 3.7" BW1+0.33 to 3.3"
29.	148 150 152	85 85 85		BW1+2.68 to 4.8" BW1+1.18 to 3.1" BW1 + 2.87 to 7.7"

Attachment V.P.1

V.P.1-6

PDP pairs not associated with mid-span indications, column oriented, steam generator 22

				Associated PDP
	Row	Col		From To
30.	157 159	86 86		08H+3.23 to 42.1" 08H+2.32 to 43.1"
31.	157 159	86 86		09H+3.61 to 41.4" 09H+1.94 to 43.3"
32.	126 128	91 91		BW1+7.02 to 8.5" BW1+6.79 to 7.83"
33.	116 118	93 93		08H+9.76 to 18.2" 08H+3.39 to 30.4"
34.	116 118	95 95		08H+11.81 to 31.1" 08H+2.94 to 31.8"
35.	115 117	96 96		08H+32.58 to 57.6" 08H+2.02 to 43.5"
36.	133 135	96 96		BW1+2.55 to 8.6" BW1+2.25 to 2.9"
37.	141 143	96 96		BW1+3.38 to 3.9" BW1+2.31 to 2.5"
38.	143 145	96 96		09H+26.54 to 31.4" 09H+24.80 to 29.8"
39.	131 133	98 98		BW1+1.90 to 2.8" BW1+2.69 to 9.6"
40.	115 115 117	102 102 102		08H+18.23 to 42.6" 08H+25.43 to 40.6" 08H+1.32 to 51.1"
41.	114 114 116 118	103 103 103 103		08H+32.17 to 44.2" 08H+33.85 to 47.4" 08H+17.94 to 42.0" 08H+8.71 to 30.8"
42.	155 157	104 104		09H+32.91 to 38.9" 09H+30.97 to 39.8"

Attachment V.P.1				
V.P.1-6				
PDP pairs not associated with mid-span indications, column oriented, steam generator 22				
				Associated PDP
	Row	**Col**		**From To**
43.	152 154 156 158	105 105 105 105		09H+28.47 to 37.1" 09H+29.25 to 37.3" 09H+19.68 to 38.0" 09H+21.29 to 35.9"
44.	153 155	106 106		09H+28.01 to 36.2" 09H+27.07 to 37.8"
45.	116 118	109 109		08H+22.92 to 43.0" 08H+21.60 to 41.7"
46.	153 155	114 114		09H+2.25 to 38.5" 09H+28.78 to 39.1"
47.	153 155	116 116		09H+25.59 to 38.8" 09H+29.61 to 40.4"
48.	147 149 151 153	120 120 120 120		09H+22.00 to 30.8" 09H+22.10 to 31.5" 09H+28.98 to 35.6" 09H+25.20 to 39.8"
49.	148 150	127 127		09H+25.29 to 37.2" 09H+23.54 to 35.5"
Note: Based on ECT analysis and ECT orientation of 150-127, the deposit was oriented toward 148-127 and slightly toward 149-128, which both had deposits at the same height, suggesting the possibility of a three way bridge. Orientation data was not available for 148-127 or 149-128.				
50.	130 132	129 129		09H+14.48 to 17.4" 09H+14.40 to 18.2"
51.	142 142 144	135 135 135		09H+12.89 to 27.7" 09H+13.81 to 31.0" 09H+14.09 to 32.1"
52.	141 143	136 136		09H+20.82 to 34.3" 09H+14.62 to 33.9"
53.	102 104	139 139		08H+17.02 to 25.2" 08H+21.23 to 28.2"
54.	115 117	152 152		08H+28.79 to 40.6" 08H+28.39 to 51.1"

Attachment V.P.1				
V.P.1-6				
PDP pairs not associated with mid-span indications, column oriented, steam generator 22				
				Associated PDP
	Row	Col		From To
55.	83 85	154 154		07H+19.90 to 28.4" 07H+20.94 to 28.4"
56.	85 85 87	154 154 154		08H+13.69 to 19.9" 08H+13.88 to 20.4" 08H+14.44 to 21.3"
57.	114 116	155 155		08H+31.57 to 45.5" 08H+31.19 to 43.8"
N/A	118 120	155 155		TSC+0.11 to 1.0" TSC+0.00 to 1.0"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.				
58.	86 88	157 157		BW1+4.22 to 5.01" BW1+2.57 to 3.3"
59.	113 115 117	158 158 158		08H+24.95 to 39.6" 08H+37.34 to 53.6" 08H+11.34 to 50.8"
60.	102 104	159 159		08H+35.83 to 40.0" 08H+35.89 to 41.8"
61.	110 112	159 159		BW1+1.31 to 2.4" BW1+2.75 to 3.2"
62.	108 110	161 161		BW1+1.65 to 3.6" BW1+2.27 to 3.4"
N/A	106 108	163 163		TSC+0.00 to 0.6" TSC+0.12 to 1.9"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.				
63.	102 104	165 165		08H+31.35 to 39.1" 08H+31.33 to 40.4"
64.	92 94	167 167		BW1+3.06 to 5.2" BW1+2.61 to 3.8"
65.	63 65	168 168		07H+30.02 to 41.2" 07H+30.44 to 43.2

Attachment V.P.1				
V.P.1-6				
PDP pairs not associated with mid-span indications, column oriented, steam generator 22				
				Associated PDP
	Row	Col		From To
66.	64 66	169 169		07H+33.53 to 48.0" 08H+1.88 to 4.0"
67.	64 66	171 171		07H+28.72 to 43.8" 08H-5.32 to -1.9"
68.	64 66	173 173		07H+28.46 to 41.5" 07H+27.92 to 41.8"
N/A	84 86 88	173 173 173		TSC+0.22 to 1.4" TSC+0.10 to 1.2" TSC+0.00 to 6.3"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.				
69.	60 62 64	177 177 177		07H+32.71 to 44.4" 07H+34.21 to 45.8" 07H+36.44 to 47.5"
70.	59 61 63 65	178 178 178 178		07H+35.33 to 38.7" 07H+25.09 to 36.8" 07H+23.00 to 37.0" 07H+23.24 to 34.8"
71.	59 61	178 178		BW1+3.57 to 4.8" BW1+2.37 to 3.4"

Attachment V.P.1				
V.P.1-6				
PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 22 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit.)				
				Associated PDP
	Row	**Col**		**From To**
N/A	22 22 22 22 21	19 19 19 19 20		TSH+1.06" TSH+2.14" TSH+2.97" TSH+3.60" TSH+0.01 to 13.6"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.				
1.	71 70	30 31		08H+1.37 to 2.9" 08H+1.98 to 2.6"
2.	75 74	30 31		08H+1.96 to 3.0" 08H+1.33 to 2.9"
3.	116 117	35 36 *		08H+42.90 to 47.3" 08H+42.18 to 43.1"
4.	129 130 131 132	40 41 42 43		09H+3.88 to 14.4" 09H+5.00 to 15.5" 09H+5.88 to 15.6" 09H+4.81 to 15.9"
5.	108 109	47 48		BW1+0.69 to 4.8" BW1+1.22 to 4.6"
6.	115 116 115	52 53 54		08H+40.90 to 60.4" 09H+2.01 to 2.9" 08H+32.80 to 48.5"
7.	143 143 142 143	54 54 55 56 *		09H+24.31 to 30.6" 09H+5.14 to 8.7" 09H+6.30 to 27.6" 09H+25.88 to 28.8"
8.	117 116 117	68 69 70		08H+11.33 to 42.0" 08H+43.47 to 49.2" 08H+13.45 to 49.3"

Attachment V.P.1				
V.P.1-6				
PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 22 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit.)				
				Associated PDP
	Row	Col		From To
9.	126 128 125 125 129	69* 69* 70 70 70		BW1+6.06 to 6.3" BW1+6.18 to 6.3" BW1+5.31 to 5.7" BW1+5.93 to 6.4" BW1+6.17 to 6.4"
10.	117 116 117 116	72 73 74 75 *		08H+11.51 to 49.5" 08H+13.86 to 43.6" 08H+10.69 to 49.5" 08H+10.93 to 43.8"
11.	100 101	75 76		05H+22.7 to 43.5" 05H+22.11 to 35.9"
12.	118 116 117 116 118	75 * 75 * 76 77 * 77 *		08H+13.81 to 42.6" 08H+10.93 to 43.8" 08H+10.94 to 47.9" 08H+11.52 to 42.6" 08H+13.93 to 43.6"
13.	152 152 153	77 77 78		09H+23.87 to 30.1" 09H+29.58 to 36.4" 09H+29.92 to 38.4"
14.	124 123	79 80 *		BW1+2.64 to 6.2" BW1+1.48 to 4.0"
15.	118 117 116 118	79 80 81 * 81 *		08H+25.32 to 34.3" 08H+36.82 to 43.4" 08H+13.88 to 41.4" 08H+14.82 to 42.6"
16.	155 156 157	80 * 79 80 *		09H+3.32 to 38.6" 09H+4.80 to 40.00" 09H+4.80 to 40.8"
17.	147 146 148	80 81* 81*		BW1+2.66 to 4.5" BW1+2.95 to 4.8" BW1+2.57 to 3.6"
18.	116 118 117	81 * 81 * 82		08H+13.88 to 41.4" 08H+14.82 to 42.6" 08H+13.51 to 34.6"

Attachment V.P.1

V.P.1-6

PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 22 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit.)

	Row	Col		Associated PDP From To
19.	155 157 156 155 157	80 * 80 * 81 82 * 82 *		09H+3.32 to 38.6" 09H+4.80 to 40.8" 09H+30.65 to 40.1" 09H+1.89 to 39.1" 09H+28.33 to 41.2"
20.	156 157 158	83 * 84 83 *		09H+5.81 to 40.2" 09H+3.42 to 41.2" 09H+19.58 to 41.8"
21.	158 157	83 84		08H+4.71 to 43.4" 08H+3.8 to 44.0"
22.	116 117 116	85 * 86 87		08H+14.44 to 43.3" 08H+10.44 to 43.0" 08H+38.63 to 42.6"
23.	157 159 158 159	86 * 86 * 87 88		09H+3.61 to 41.4" 09H+1.94 to 43.3" 09H+4.40 to 41.8" 09H+5.40 to 42.2"
24.	118 117 118 117 116 118	89 90 91 92 93 * 93 *		08H+1.46 to 42.7" 08H+23.17 to 24.7" 08H+1.09 to 42.3" 08H+1.86 to 43.2" 08H+9.76 to 18.2" 08H+3.39 to 30.4"
25.	116 118 117 116 118	93 * 93 * 94 95 * 95 *		08H+9.76 to 18.2" 08H+3.39 to 30.4" 08H+5.67 to 18.7" 08H+11.81 to 31.1" 08H+2.94 to 31.8"
26.	116 115 117 118 118	95 96 * 96 * 95 95		08H+11.81 to 31.1" 08H+32.58 to 57.6" 08H+2.02 to 43.5" 08H+2.94 to 31.8" 08H+36.06 to 42.5"
27.	128 129	97 98		BW1+2.49 to 7.5" BW1+3.95 to 20.00"

Attachment V.P.1				
V.P.1-6				
PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 22 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit.)				
				Associated PDP
	Row	Col		From To
28.	117 116 115 115 117	100 101 102 * 102 * 102 *		08H+4.98 to 51.8" 08H+12.73 to 25.1" 08H+18.23 to 42.6" 08H+25.43 to 40.6" 08H+1.32 to 51.1"
29.	116 118 117 116 117 118 118 117 116 118 117	103 * 103 * 104 105 106 107 107 108 109 * 109 * 110		08H+17.94 to 42.0" 08H+8.71 to 30.8" 08H+7.63 to 50.4" 08H+15.22 to 42.6" 08H+15.69 to 50.1" 08H+19.63 to 31.0" 08H+40.09 to 42.7" 08H+13.07 to 51.0" 08H+22.92 to 43.0" 08H+21.60 to 41.7" 08H+20.31 to 49.0"
30.	155 156 155	106 107 108		09H+27.07 to 37.8" 09H+19.67 to 39.7" 09H+19.31 to 39.9"
31.	155 156 155	110 111 112		09H+25.94 to 40.7" 09H+29.31 to 41.0" 09H+24.30 to 40.0"
32.	147 146 148 149 149	114 115 * 115 * 116 116		09H+31.83 to 33.4" 09H+20.82 to 31.2" 09H+21.48 to 33.3" 09H+19.72 to 27.2" 09H+19.91 to 26.6"
33.	153 155 154	116 * 116 * 117		09H+25.59 to 38.8" 09H+29.61 to 40.4" 09H+32.82 to 39.2"
34.	154 153	119 120 *		09H+9.13 to 39.3" 09H+25.20 to 39.8"
35.	133 134	120 121		BW1+1.99 to 3.8" BW1+1.70 to 3.8"

Attachment V.P.1

V.P.1-6

PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 22 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit.)

				Associated PDP
	Row	Col		From To
36.	150 148 149	127 * 127 * 128		09H+23.54 to 35.5" 09H+25.29 to 37.2" 09H+28.80 to 37.5"
Note: Based on ECT analysis and ECT orientation of 150-127, the deposit was oriented toward 148-127 and slightly toward 149-128, which both had deposits at the same height, suggesting the possibility of a three way bridge. Orientation data was not available for 148-127 or 149-128.				
37.	141 140	136 * 137		09H+20.82 to 34.3" 09H+23.69 to 26.1"
38.	115 114 116	154 155 * 155 *		08H+41.90 to 48.0" 08H+31.57 to 45.5" 08H+31.19 to 43.8"
39.	116 117	155 * 156		08H+31.19 to 43.8" 08H+16.01 to 43.8"
N/A	118 120 119	155 * 155 * 156		TSC+0.11 to 1.0" TSC+0.00 to 1.0" TSC+0.05 to 0.5"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.				
40.	94 95	157 158		BW1+1.90 to 3.5" BW1+1.90 to 2.6"
41.	113 115 114	158 * 158 * 159		08H+24.95 to 39.6" 08H+37.34 to 53.6" 08H+27.18 to 38.5"
42.	107 108	160 161 *		BW1+2.82 to 4.3" BW1+1.65 to 3.6"
N/A	106 108 107	163 * 163 * 164		TSC+0.00 to 0.6" TSC+0.12 to 1.9" TSC+0.04 to 2.3"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.				

Attachment V.P.1				
V.P.1-6				
PDP pairs not associated with mid-span indications, diagonally oriented, steam generator 22 (asterisk denotes a tube which is also associated with an adjacent column oriented deposit.)				
				Associated PDP
	Row	**Col**		**From To**
43.	62 63	171 172		BW1+1.97 to 3.65" BW1+3.11 to 4.0"
44.	64 63 64	171 * 172 173 *		07H+28.72 to 43.8" 07H+40.54 to 46.7" 07H+28.46 to 41.5"
45.	84 86 85	173 * 173 * 174		TSC+0.22 to 1.4" TSC+0.10 to 1.2" TSC+2.53 to 5.4"
Note: Based on experience and FOSAR observation, tubesheet deposits appear to be normal sludge deposits.				
46.	62 61	177 178		BW1+2.70 to 3.8" BW1+2.37 to 3.4"
47.	39 40	184 185		BW1+2.70 to 4.3" BW1+2.85 to 4.6"

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