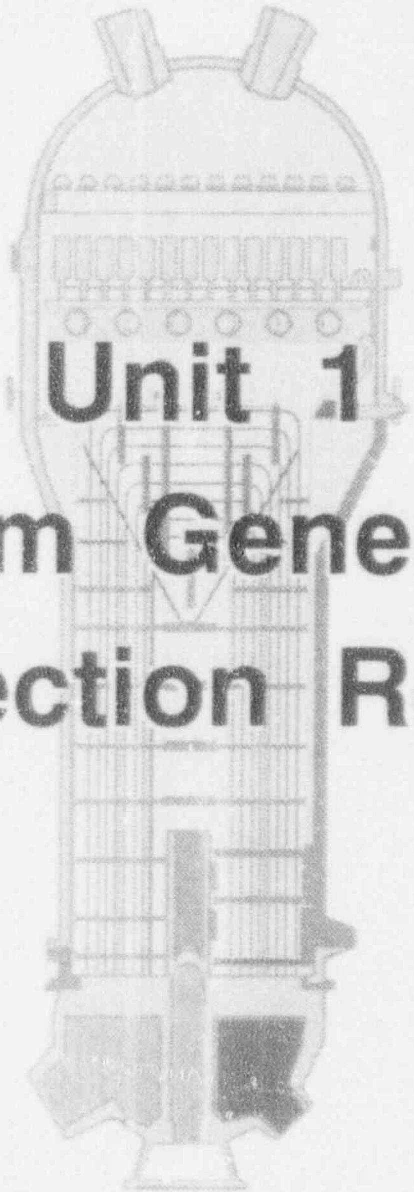
Palo Verde Nuclear Generating Station



Unit 1 Steam Generator Inspection Report

October 1993

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

Prior to the Unit 1 fourth refueling outage, axial free span cracks in steam generator (SG) tubes were detected in PVNGS Unit 2 during its fourth refueling outage. These axial cracks, located in the upper bundle, were found to be the cause of the tube rupture which forced shutdown of Unit 2. Due to the complex variety of causal factors which could be transportable between the three PVNGS units, the Unit 1 SG inspection program was specifically designed to identify this degradation mechanism. Eddy current testing (ECT) in Unit 1 by both bobbin coil probe and motorized rotating pancake coil (MRPC) probe found no evidence of axial cracks in the upper bundle area which had been identified both by analysis and inspection in Unit 2.

However, the inservice eddy current inspection of the Unit 1 steam generators did identify circumferential cracking at the top of the tubesheet expansion transition region of SG 11 and SG 12. This cracking was identified with an MRPC probe and characterized as both outside diameter (OD) and inside diameter (ID) initiated. Ultrasonic testing (UT) methods were used on selected tubes to verify the ECT determination of their nature. In situ pressure testing was used to verify Regulatory Guide (RG) 1.121 compliance.

In addition to the circumferential cracks, ECT inspection also identified 17 axial cracks at the tubesheet (primarily in underexpanded tubes) and 111 single volumetric indications (SVIs). The axial cracks in underexpanded tubes is a well understood phenomenon associated with crevices between the outer tube wall and the tubesheet when tubes are either not expanded or partially expanded. SVIs can be attributed to either manufacturing flaws such as burnishing marks or corrosion/wear mechanisms. They may indicate the presence of intergranular attack or pitting. The presence of six SVI's in the arc regions may indicate IGA in this area, but does not show the accelerated IGSCC axial cracking phenomenon observed in Unit 2.

The circumferential cracking mechanisms at work in Unit 1 are primary water stress corrosion cracking (PWSCC) and outside diameter stress corrosion cracking (ODSCC). PWSCC of Alloy 600 requires the simultaneous conditions of stress, a susceptible material, and a suitable environment (including temperature). Additionally, the degradation is a function of time. Cracking is typically interganular. In PWR SGs, high temperature primary water can cause PWSCC of Alloy 600 at locations of high residual tensile stress. These areas of Alloy 600 PWSCC susceptibility are commonly located in the tubing at the top of the tube sheet, where there is a short transition section between tubing that has been expanded within the tube sheet and the remainder of the tube.

There is a known temperature effect on SCC in Alloy 600 tubing. At temperatures above approximately 500°F, PWSCC can occur in less time at constant stress levels. Failure rates as a function of temperature can be expressed by an Arrhenius relationship. Since PWSCC is highly dependent on material properties, residual stress, and fluid temperature, preventative measures are limited to reduction in RCS temperatures (T_{HOT}) and stress relieving the expansion zone. Tube sleeving is a potential repair mechanism.

Some corrective actions for ODSCC were previously implemented in Unit 1 and may have had a beneficial impact on ODSCC in the upper bundle. These included molar ratio control, elevated secondary system pH (to reduce iron transport), and elevated hydrazine concentration. As a result of ODSCC freespan cracking in the upper bundle of Unit 2 SGs, enhanced leakage monitoring and response procedures were developed for all units. Implementation of boric acid treatment is scheduled for the startup following the current outage (U1R4). In response to the circumferential cracking in Unit 1, sludge lancing was performed in Unit 1. Finally, all tubes in Unit 1 with circumferential cracks will be removed from service by plugging.

The probability and consequences of an accident previously evaluated is not increased as a result of the circumferential cracking in Unit 1. In situ pressure tests were conducted to verify the margins of safety specified in RG 1.121 were maintained. The observed crack sizes indicate RG 1.121 limits were not exceeded in one cycle of operation. Therefore, there are no special restrictions placed on the Unit 1 inspection interval.

II. PROBLEM DESCRIPTION AND SAFETY ASSESSMENT

Two corrosion mechanisms are addressed in this report: susceptibility of PVNGS Unit 1 SGs to free span axial cracking (similar to that which occurred in PVNGS Unit 2) and the discovery of circumferential ID and OD cracks at the top of the hot leg tubesheets of both SGs in Unit 1.

A. Free Span Cracking Transportability

The free span cracking phenomenon was first observed in PVNGS Unit 2 during the ECT inspections conducted in the Spring of 1993 during the fourth refueling outage (U2R4). This mechanism resulted in the rupture of a tube during power operation at the end of Cycle 4. This event and the subsequent analysis is discussed in depth in the "Unit 2 Steam Generator Tube Rupture Analysis Report" submitted to the NRC staff as enclosure (2) to William Conway's letter 102-02569-WFC/JRP dated July 18, 1993. Briefly, the report concluded that free span axial cracks had occurred in the upper bundle of the SGs in Unit 2 as a result of Intergranular Stress Corrosion Cracking (IGSCC) initiated at the outer diameter due to a combination of contributing factors including: tube-to-tube crevice formation, ridge deposits, increased sulfate levels probably due to a resin intrusion and mildly caustic crevice pH. Additional factors which played a part in some of the tubes analyzed included substandard microstructure and cold working from manufacturing scratches.

The complex synergistic effect of these causal factors did not allow the task force to conclude the relative weights of these factors and lead to the concern that the corrosion mechanism might be transportable to Units 1 and 3. The scope of ECT inspection for U1R4 was adjusted to ensure that if the phenomenon was at work in a manner similar to Unit 2 it would be discovered. However, neither bobbin nor MRPC ECT methods have discovered any free span axial cracking in the Unit 1 steam generators. Slight freespan corrosion damage may be present on a small number of tubes in the form of volumetric indications in Unit 1. The lack of free span axial cracks is attributed to differences in chemical environments between the Units. Unit 1 is different from Unit 2 for the following reasons: there is no evidence of resin intrusion into the Unit 1 SGs, Unit 1 molar ratio control was successful in reducing crevice pH earlier in plant life than Unit 2, and Unit 1 has had more power reductions and trips over its life than Unit 2 which would promote the wetting and flushing of deposit areas minimizing the hideout of contaminant species. Factors which were present in Unit 1 include tube bowing, deposits high in the tube bundle and manufacturing burnish marks. The lack of axial cracks in Unit 1 indicates that the causal factors observed in Unit 1 alone have not produced the accelerated cracking observed in Unit 2.

Although no axial cracks were observed in Unit 1, it is understood that this phenomenon could occur if the proper combination of causal factors are permitted to develop. In order to prevent that from occurring a multi-tier approach to mitigation has been developed. This approach is set forth in the section entitled "Operating Plan."

The free span cracking phenomenon has no safety impact on Unit 1. Based on the failure to observe any upper bundle axial cracking in Unit 1 it is concluded that the accelerated free span cracking phenomenon is not at work in Unit 1. The implementation of preventive/mitigating actions (see "Operating Plan") further ensure that accelerated cracking will not initiate in Unit 1. The multiple rupture of steam generator tubes during a main steam line break (MSLB) accident was analyzed as part of the Unit 2 restart effort (see Reference 13) and has predicted dose consequences well within 10CFR100 limits.

B. Circumferential Cracking

The circumferential cracking phenomenon was first observed in PVNGS Unit 1 during the ECT inspections conducted during the current refueling outage (U1R4). This issue is reported for the first time in this document.

The circumferential cracks observed in Unit 1 occurred at the hot leg top of tubesheet initiating from both the inside (PWSCC) and outside (ODSCC) of tubes (as determined by ECT). Both corrosion mechanisms have been observed throughout the industry, and do not represent new corrosion mechanisms. The PWSCC is primarily addressed by reduction of primary coolant temperature to take advantage of the temperature dependence shown by SCC rates. Secondary side ODSCC is addressed by changes in chemical environment as well as benefiting from temperature reduction. Many of the actions which prevent free span axial cracking have a similar effect on circumferential cracking at the tubesheet. Additional actions taken or planned to address circumferential cracking are:

- Sludge lancing was conducted in both Unit 1 SGs to remove the sludge pile where corroding species can concentrate and attack the tube outer surface.
- Tubes with circumferential cracks will be plugged and staked to remove all cracked tubes from service. Sleeving, which requires Technical Specifications changes, may be used in the future to repair circumferentially cracked tubes .

The conditions observed in Unit 1 that contribute to circumferential cracking are present in all three units, however no factors have been identified that could lead to more aggressive corrosion in any one unit. Analyses for Unit 1 determined that the RG 1.121 requirements are being met. Therefore, although transportability of the circumferential cracking phenomenon from Unit 1 to Units 2 and 3 is possible it is not considered to be a significant issue.

The safety impact of this phenomenon is not significant in Unit 1 because the safety margins specified in RG 1.121 were maintained, the use of the preventive/mitigating actions listed under "Operating Plan" are expected to retard the circumferential cracking, and the multiple rupture of steam generator tubes during a MSLB accident was analyzed as part of the Unit 2 restart effort (see Reference 13) and has predicted dose consequences well within 10CFR100 limits.

III. STEAM GENERATOR OPERATING HISTORY

A. Steam Generator Chemistry

Steam generator chemistry is a primary factor affecting the rate of outer diameter stress corrosion cracking. Therefore, a review of steam generator chemistry was conducted to determine if chemistry conditions could be identified that account for the lack of freespan axial cracks and the occurrence of circumferential cracks.

The chemistry control program at PVNGS was originally developed under the guidance of Combustion Engineering (Reference 10). The program's purpose was to establish specific limits for impurities in the SGs, action levels for exceeding limits, and hold points during power ascensions to ensure chemistry was satisfactorily maintained. This program has been revised and enhanced to reflect developments identified in EPRI guidelines, as well as the incorporation of lessons learned at PVNGS and other utilities. Initially, action was taken when SG chemistry exceeded the stated guidelines. In late 1989, an ALARA (As Low As Reasonably Achievable) philosophy was implemented in order to keep contaminant levels as low as practical. In an attempt to improve the chemistry in the crevice region of the SGs, this ALARA principle was later enhanced with "min/max" chemistry control (see Figure III-1). Min/max objectives are to minimize contaminant input into the SG, maximize the return or removal of SG contaminants, and to mitigate the corrosive environment within the SG.

B. Unit 1 Secondary Water Chemistry

Plant bulk water chemistry (daily operating chemistry parameters)was maintained in accordance with plant procedures, CE Owners guidelines, and EPRI guidelines. Since initial startup, all three units have operated with essentially identical chemical control programs (ammonia/hydrazine with full flow condensate polishers) and the SG bulk water chemistry data for Unit 1 was consistent with Units 2 and 3 data. In January 1993 elevated hydrazine was implemented and on April 19, 1993 the use of ethanolamine (ETA) for secondary system pH control was initiated in Unit 1. The operating parameter that best depicts the SG bulk chemistry condition is the molar ratio (the equivalent ratio of sodium to chloride). Prior to 1993, the molar ratio trends for all three units indicated a chronic caustic chemistry control pattern. The concentrations of sodium in SG blowdown, while consistently within EPRI and Combustion Engineering Owner's Group (CEOG) specifications, were higher (on an equivalent weight basis) than chloride levels.

Despite having a common feedwater source, operational bulk water chemistry differs between SGs within a particular unit. This difference may be due to blowdown efficiency or steaming rates, however, operational bulk water chemistry is maintained through control of blowdown flow rates.

Prior to March 1993, operating bulk water chemistry was monitored via the hot leg blowdown sample point. Since then, the downcomer sample point has been used to monitor impurity levels. The downcomer sample impurity concentrations are approximately a factor of two times higher than hot leg blowdown sample concentrations (based upon recent sampling in Units 2 and 3).

In summary, the Unit 1 bulk water chemistry has been similar to Units 2 and 3. Recent modifications in condensate polisher operation have resulted in improved molar ratio control. ETA pH control has demonstrated a positive reduction in iron transport from approximately three pounds per SG per day to 1 pound per SG per day. Furthermore, hydrazine levels have been increased in an attempt to reduce the electrochemical potential in the SGs.

C. Chemistry Transients

A review of operating chemistry data, shutdown hideout return data, and sludge sample data for Unit 1 has been conducted. This review has identified only one significant chemistry excursion. That event, a condenser tube rupture with subsequent ionic impurity breakthrough from the condensate polishers, occurred December 11, 1985. During this event, SG 11 pH dropped to a low of 2.4 and SG 12 pH dropped to 2.5. The highest impurity levels recorded were:

Cation conductivity	1250 micromhos
Chloride	35 ppm
Sulfate	27 ppm
Sodium	14 ppm

The unit was shutdown and pH was restored to normal ranges approximately 24 hours following initiation of the event.

1. Condenser Leaks

A condenser tube leak assessment report from August 1992 (Reference 11) discusses the Unit 1 condenser tube leak history since 1986. Other than the event noted above, Unit 1 tube leaks have been significantly below 1 gpm, with an average of 0.07 gpm per event. Five different events were identified between 1987 and 1989. Unit 1 has had no tube leaks since condenser modifications were completed in May of 1989.

2. Steam Generator Layup

The layup conditions were reviewed for any impact on SG tube degradation. Unit 1 had experienced some periods when the SGs were dry and/or without a nitrogen overpressure. Those transient layup conditions were not considered to have aggravated the SG tube condition. SG layup conditions were evaluated by Combustion Engineering (Reference 8).

D. Hideout Return Studies

Hideout return data is considered the most accurate indicator of the chemistry present within SG crevices during operation and, as such, can provide insight into potential damage mechanisms. A review of data obtained during shutdowns was conducted for the three PVNGS units to determine what, if any, differences had existed between the hideout return characteristics of the six SGs. A total of 53 shutdown data sets covering January 1987 through March 1993 were reviewed. The complete results of this review are documented in Reference (1).

This review of hideout return chemistry data analysis concludes that all three units have operated with caustic crevice environments. MULTEQ pH predictions for four Unit 1 shutdowns prior to September 1993 were between 9.7 and 10.6 (see Table III-1). Due to corrective actions begun in late 1992, Unit 1 crevice chemistry now appears to be in the acidic regime (MULTEQ calculated pH values of 1.7 and 2.8). This change in crevice chemistry will assist in the mitigation of free span ODSCC in Unit 1.

E. Recent Secondary Chemistry Control Changes

PVNGS has implemented several changes to the secondary chemistry control program. The changes have included modifications to the condensate demineralizer operating practices in order to reduce the sodium source input into the SGs. The following policies were implemented:

- Improved resin separation techniques (January 1989)
- Reduction in anion regeneration frequencies (November 1990)
- Performance of a second cation resin regeneration in each regeneration cycle to ensure maximum cation resin capacity is available (1992)

In addition, in 1992, an overnight soak of the regenerated anion resin charge to reduce sulfate levels was implemented. Dedicated operators were assigned to the system to give greater consistency in system operations. Finally, condensate demineralizer bypass operation is being used successfully to reduce the molar ratio.

Other changes were also initiated in 1992. Feedwater pH was optimized to >9.15 with full flow condensate demineralizer operation to reduce iron transport. Secondary system air inleakage was significantly reduced. In conjunction with the operational changes to reduce iron transport, feedwater iron specifications were reduced by 50% (to < 10 ppb). In late 1992, the feedwater hydrazine specification was increased to > 100 ppb (from the 40-50 ppb range). This change was made to reduce the electrochemical potential in the SG.

Molar ratio control was also implemented in 1992. Figure III-2 provides trend data of Unit 1 molar ratio data back to December of 1991. The molar ratio control program is intended to maintain the sodium to chloride ratio < 1.0. The PVNGS specification was adjusted to 0.5 to 1.2 to prevent the development of excessive acid conditions in the SG. The success of this program is evident in the reduced crevice pH values calculated following the September 1993 shutdown.

F. Summary

Unit 1 SG chemistry has been maintained within plant and industry guidelines. Out of specification conditions were corrected within the time periods specified in EPRI guidelines. Prior to 1993, Unit 1 bulk chemistry did not significantly differ from Units 2 and 3. All three units had operated with caustic crevice chemistry and high levels of contaminant return from downpowers.

Beginning in 1993, the following improvements in chemistry control were initiated in Unit 1:

- Elevated hydrazine to reduce electrochemical potential
- ETA injection for pH control (reduced iron transport)
- Improved molar ratio control through optimization of condensate polisher operation

The information above leads to the conclusion that SG bulk water chemistry has historically been similar from one unit to the next. Unit 1 differs from Unit 2 in that it is not known to have had a resin intrusion problem, and recently has operated with a lower crevice pH and reduced corrosion product transport. These factors may account for the lack of freespan axial cracks in Unit 1.

The attempt to identify chemical accelerants causing ODSCC circumferential cracking was not successful. However, the empirical data shows a strong correlation between the location of the circumferential cracks and the sludge pile. The presence of both ID and OD cracks in this area leads to the conclusion that the insulating properties of the sludge may be a dominant factor that causes wall temperature to drive the SCC rates on both inner and outer diameter.

TABLE III-1

UNIT ONE STEAM GENERATOR HIDEOUT RETURN DATA SUMMARY										
Date	Jan 91		Sep 91		Jan 92		Feb 92		Sept 93	
OUTAGE TYPE	ST		FORCED		FORCED		REFUEL		REFUEL	
EFPD	169		380		473		500		438	
DAYS ON LINE	109		210		63		31		109	
FINAL TEMP. OF DATA SET	110° F		350° F		257° F		317° F		338	
GENERATOR	1	2	1	2	1	2	1	2	1	2
EPRI MULTEQ CODE PREDICTIONS										
DELTA B.P.	32.4	16.5	16.8	23.2	37.2	22.4	29.2	19.5	25.28	34.94
pH at DELTA B.P.	**10.6**	**10.3**	**10.3**	**10.5**	**9.7**	**9.7**	**10.3**	**10.2**	**1.7**	**2.2**
NEUTRAL pH	4.8	4.9	4.9	4.9	4.7	4.9	4.8	4.9	4.9	4.8
CEOG TASK 575 SPREADSHEET CALCULATED VALUES										
SODIUM, gm.	13	31			26	40	51	91	13	13
MAGNESIUM, gm.	8	15			11	15	12	12	19	18
CALCIUM, gm.	14	37			87	51	80	53	166	168
POTASSIUM, gm.	--	--			1	1	7	6	6	10
CHLORIDE, gm.	1	2			12	18	6	12	3	4
SILICA, gm.	92	273			314	353	318	526	414	463
SULFATE, gm.	17	41			80	113	26	39	564	379
CAT/AN RATIO	5.1	2.3			3.2	1.9	10.3	7.6	0.9	1.3
Na + K / Cl RATIO	19	23			3.4	3.5	14	12	7.7	6.8
EQUIV. CATIONS	1.9	4.4			6.4	5.5	7.2	9.1	10.6	10.7
EQUIV. ANIONS	0.4	1.9			2	2.9	0.7	1.2	11.8	8
EQUIV. SILICA	1.5	4.5			5.2	5.9	5.3	8.8	6.9	7.7

FIGURE III-1

Min/Max Chemistry

Minimize

Molar Ratios:

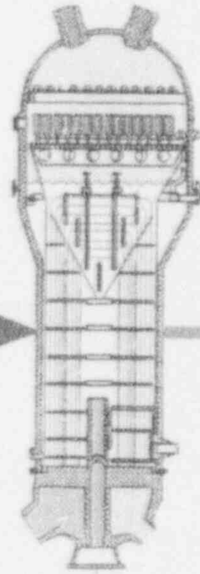
- Maintain Cation to Anion ratio within approved specifications

Source Terms:

- Control/reduce contaminant source inputs

Corrosion Product Transport:

- Maintain final feedwater Iron levels within approved specifications



Maximize

Blowdown Flow:

- **Most beneficial Abnormal Highrate schedule**

Hideout Return:

- **Downpowers Holdpoints**

Mitigation

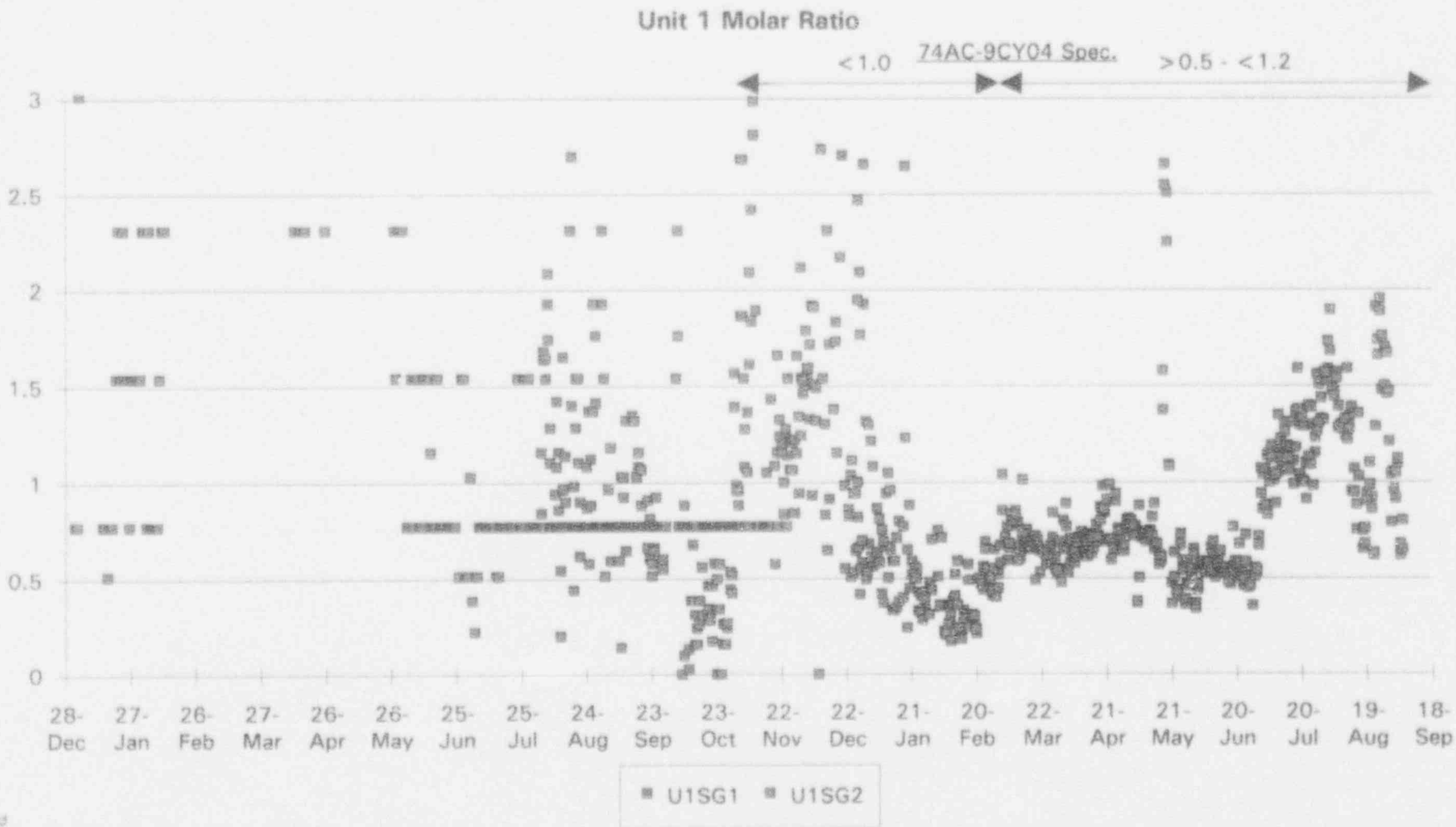
Buffer Crevices:

- Add Boric Acid

Elevated Hydrazine:

- Maintain feedwater Hydrazine levels within approved specifications

FIGURE III-2



Unit 1 Molar Ratio
<1.0
74AC-9CY04 Spec.
>0.5 - <1.2
3
2.5
2
1.5
1
0.5
0
28-Dec
27-Jan
26-Feb
27-Mar
26-Apr
26-May
25-Jun
25-Jul
24-Aug
23-Sep
23-Oct
22-Nov
22-Dec
21-Jan
20-Feb
22-Mar
21-Apr
21-May
20-Jun
20-Jul
19-Aug
18-Sep
U1SG1
U1SG2

IV. FREE SPAN AXIAL CRACKING IN UNIT 2

A tube rupture event in Unit 2 (March, 1993) led to extensive evaluation of the failure mechanism. This evaluation in Unit 2 included eddy current testing, tube pulls, laboratory analysis, historical review, and failure mode analysis. The failure occurred in the free span area above the 08H tube support. The evidence indicated that the rupture was due to IGA/IGSCC which developed as a result of tube-to-tube crevice formation. This crevice formed as a result of tube bowing between the tube supports. 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 a loss of structural integrity under normal operating conditions.

The scope of ECT inspection during the U1R4 outage was designed to ensure that if a similar problem existed in Unit 1, it would be discovered. This included an inspection of 100% of the tubing using the bobbin coil probe, a sample inspection of bobbin indications associated with the 07H through the first vertical support structures with the MRPC probe, an MRPC inspection of approximately 1800 tubes from the 08H support through the first vertical support encompassing the "MRPC" arc (the area where almost all of the free-span axial indications in Unit 2 were located - see Figure IV-5), and a checkerboard MRPC inspection sample of approximately 500 tubes from the 08H support through the first vertical support. Several improvements in ECT techniques and training enabled the analysts to determine the extent of bowing and ridge deposit formation. Figures IV-1 and IV-2 indicate the location of possible deposits as determined by ECT. Figures IV-3 and IV-4 indicate locations of tube bowing, a mechanism which may promote the formation of free span deposits. These indications of bowing and deposits are based upon ECT (MRPC) analysis and there does not appear to be a significant difference between Unit 1 and Unit 2 in the general location and number of tubes with deposits. Bowing was visually observed in Unit 2, SG 22 during U2R4. Since U2R4, ECT methods have become available to assist the analyst in detecting bowing, and this phenomenon was observed in Unit 1. Due to the lack of bowing data from U2R4, it can only be said that bowing is present in both units, but a quantitative comparison can not be made at this time.

Upon completion of the ECT inspection program no axial indications were found in the areas inspected from the 08H to vertical support area of the steam generators. However, a review of the inspection results indicate that slight freespan corrosion damage may be present on a small number of tubes in the form of volumetric indications (refer to Table XI-5 through XI-7 in the Appendices) in the Unit 1 SGs. In SG 11, two tubes were found to have an SVI associated with linear ridge deposits. This indication was not present in earlier ECT inspections. Three tubes in SG 12 were identified as having an SVI and an associated deposit. Tube R122C101 in SG 12 was also inspected by UT examination to confirm that the SVI defect (identified by ECT) was volumetric and not SCC. The UT examination confirmed the ECT disposition of the defect. It is postulated from the NDE inspections that the indications are representative of intergranular attack (IGA) or pitting. The rate of attack by these mechanisms is significantly slower than IGSCC observed in Unit 2.

This discovery of slight corrosion related damage in the arc region is not unexpected. The analysis performed in support of the Unit 2 SG tube rupture event indicated a region of deposit formation and contaminant concentration. The lack of significant resin intrusion and improved chemistry control could explain the difference in quantity and severity of defects found in Unit 1 as compared to those found in Unit 2. Based upon the SG inspection it is concluded that the accelerated damage mechanism found in Unit 2 is not active in Unit 1 SGs. Consequently, the basis for the transportability position taken in APS Letter 102-02585 (Reference 13) is supported by the U1R4 inspection results.

Note: The "MRPC" arc is the area of 1800 tubes included in the original MRPC scope. The "Bobbin" arc is a buffer region of 2000 tubes surrounding the "MRPC" arc. The data evaluated is from the 08H through the first vertical support. See Figure IV-5.

FIGURE IV-1, POSSIBLE DEPOSIT LOCATIONS, SG 11

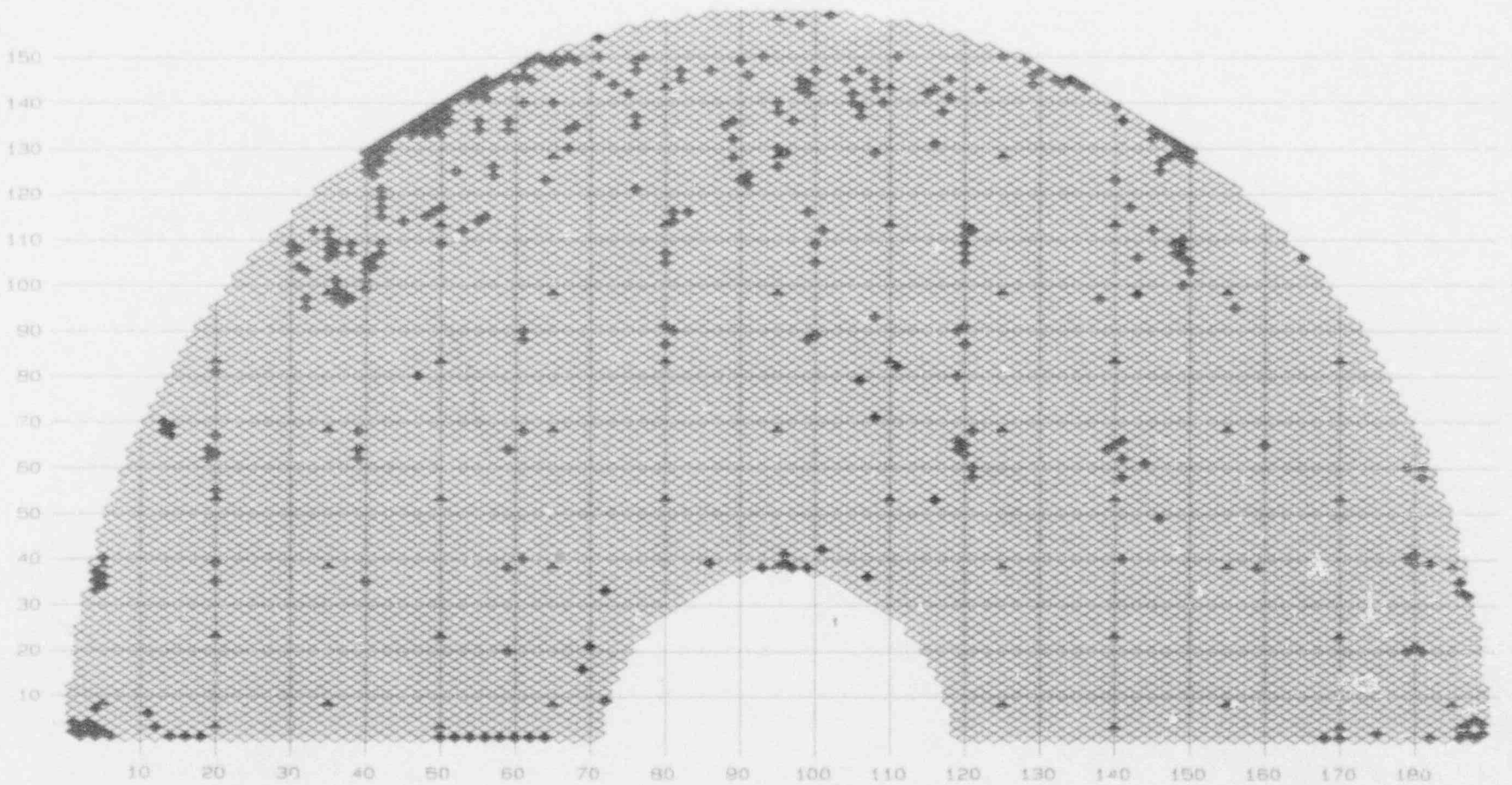
10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 11
OUTAGE DATA SET : CURRENT
Percent: PDP

DATE: 10/27/93
TIME: 12:23:54

STAYS

PLUGGED 74 PDP 268



CONAM NUCLEAR, INC. BW

FIGURE IV-2, POSSIBLE DEPOSIT LOCATIONS, SG 12

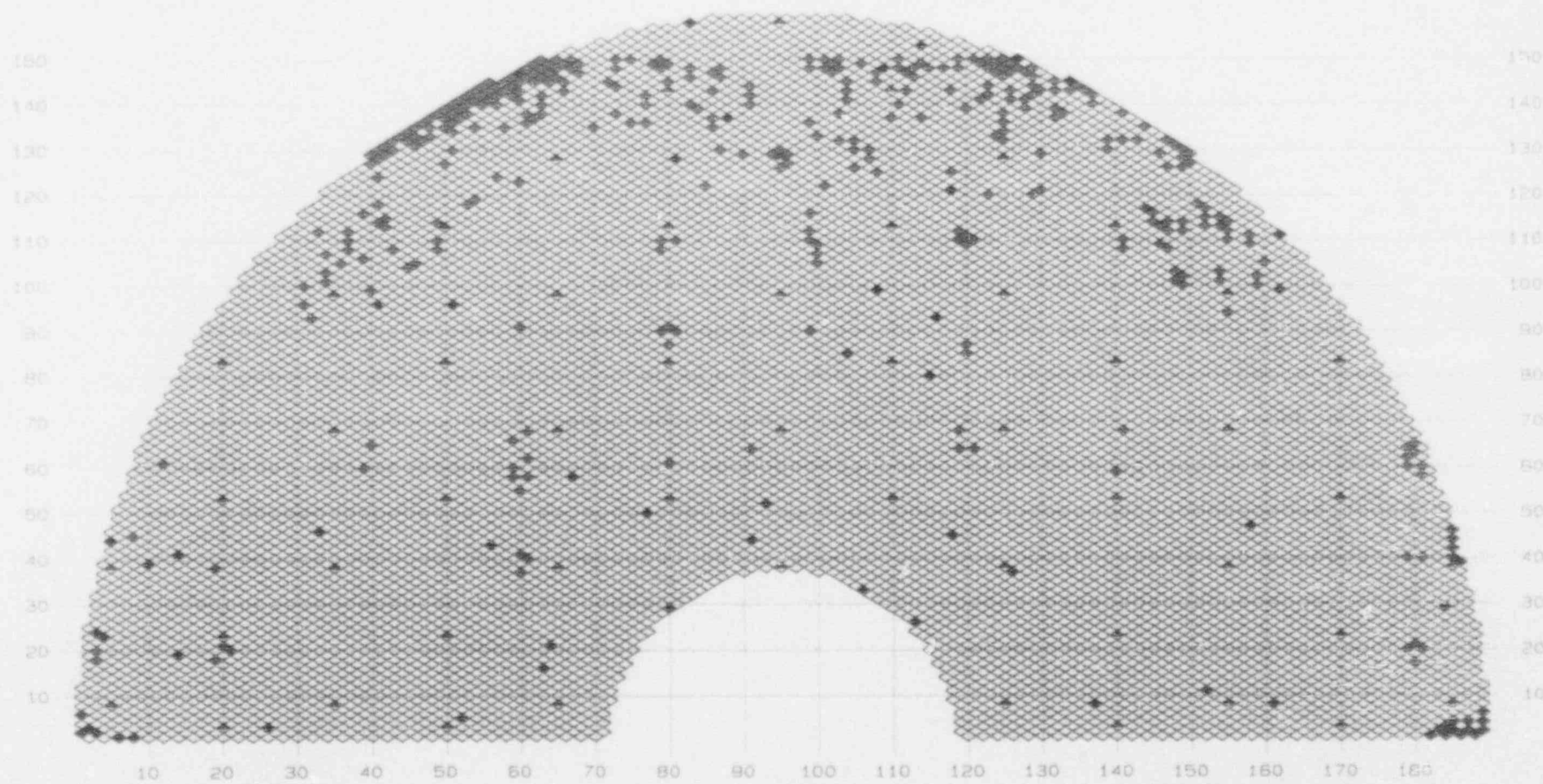
10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 12
OUTAGE DATA SET : CURRENT
Percent: PDP

DATE: 10/26/93
TIME: 13:54:02

STAYS

PLUGGED 67 ◆ PDP 346 ◆



CONAM NUCLEAR, INC. PW

FIGURE IV-3, BOWED TUBE LOCATIONS, SG 11

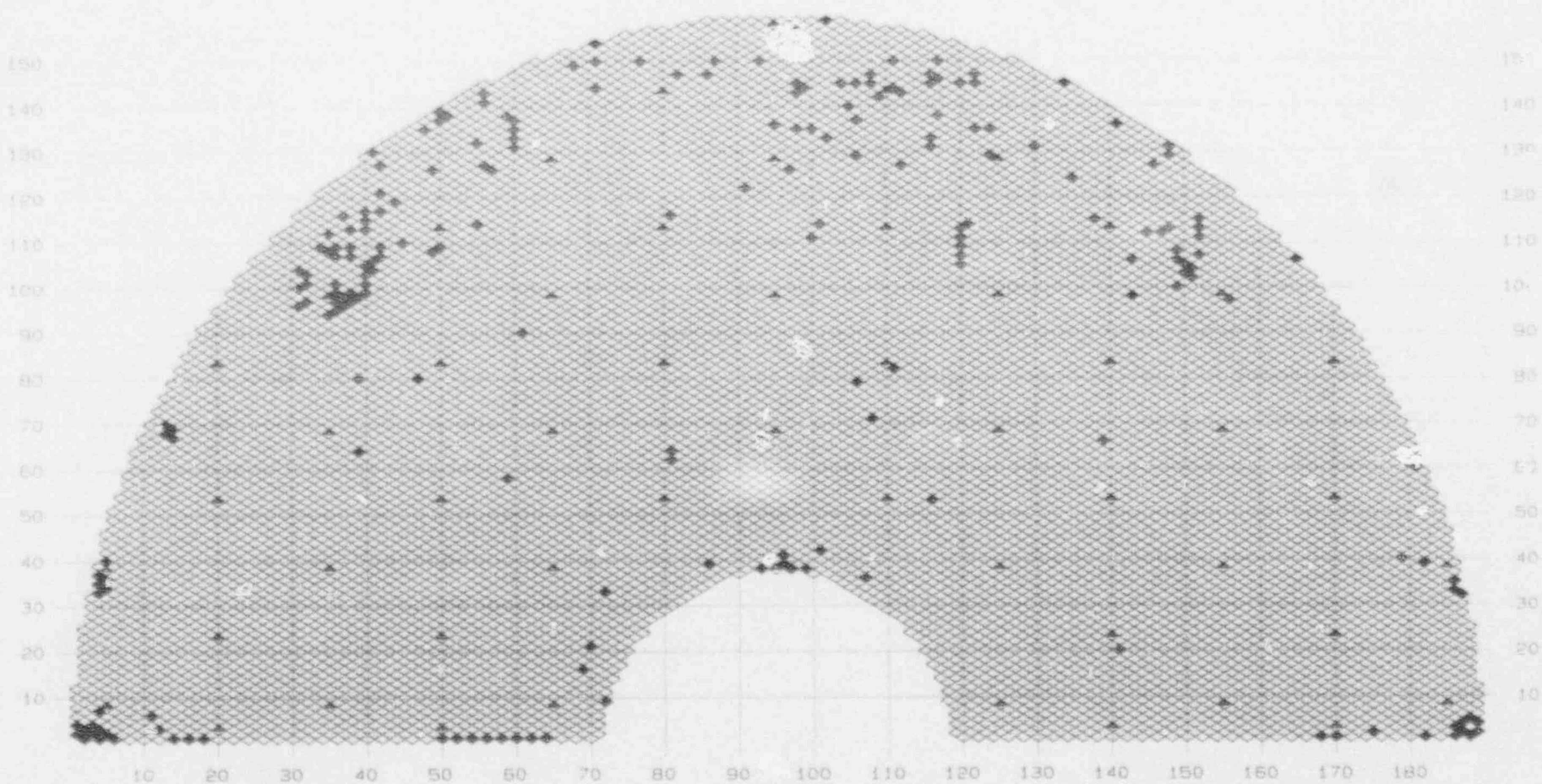
10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 11
OUTAGE DATA SET : CURRENT
Percent: BOW

DATE: 10/24/93
TIME: 10:24:15

STAYS ◆

PLUGGED 74 ◆ BOW 143 ◆



CONAM NUCLEAR, INC. BW

FIGURE IV-4, BOWED TUBE LOCATIONS, SG 12

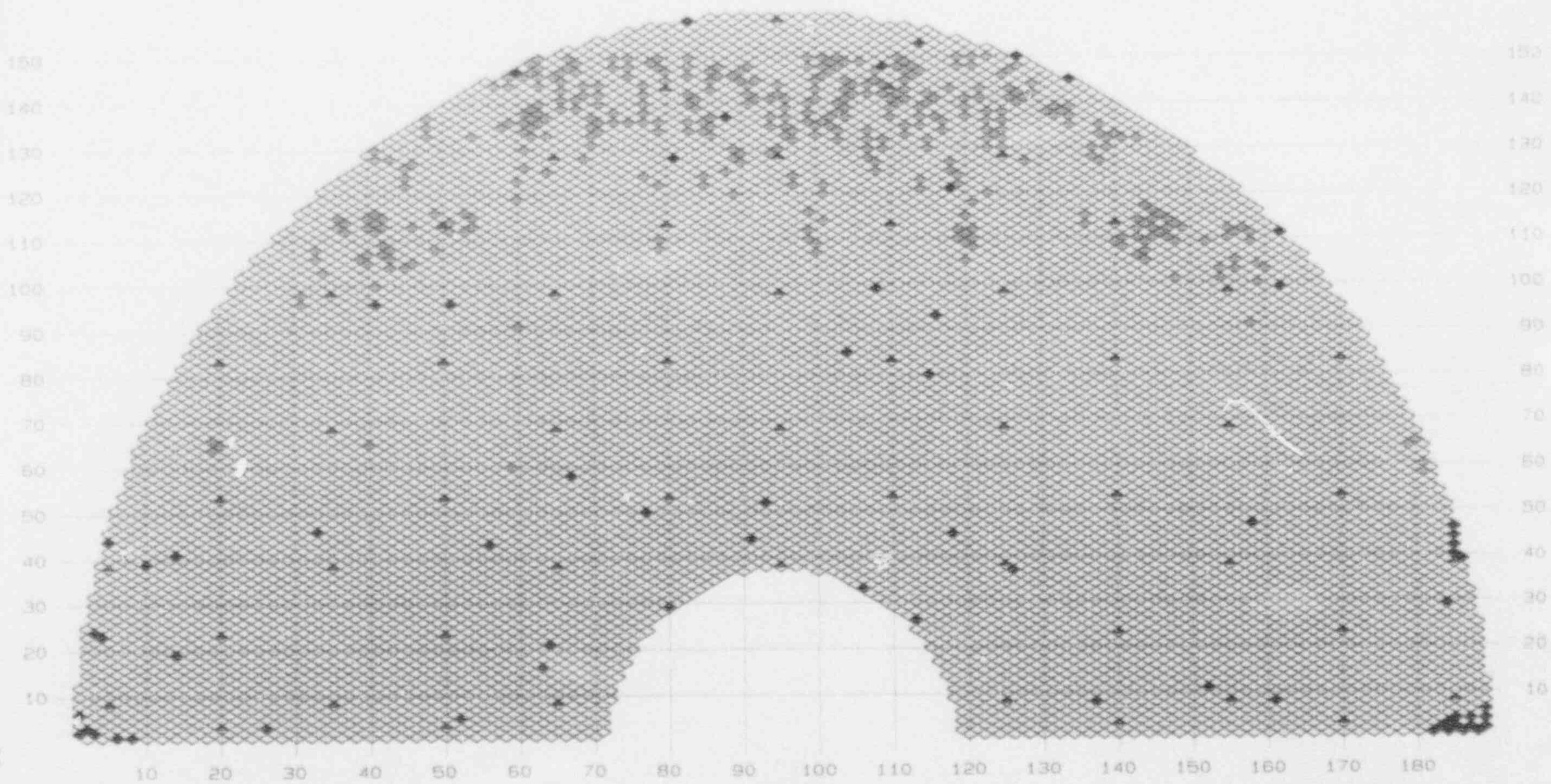
10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 12
OUTAGE DATA SET : CURRENT
Percent: BOW

DATE: 10/26/93
TIME: 13:44:33

STAYS ▲

PLUGGED 67 ◆



CONAM NUCLEAR, INC. BW

FIGURE IV-5, ARC REGIONS

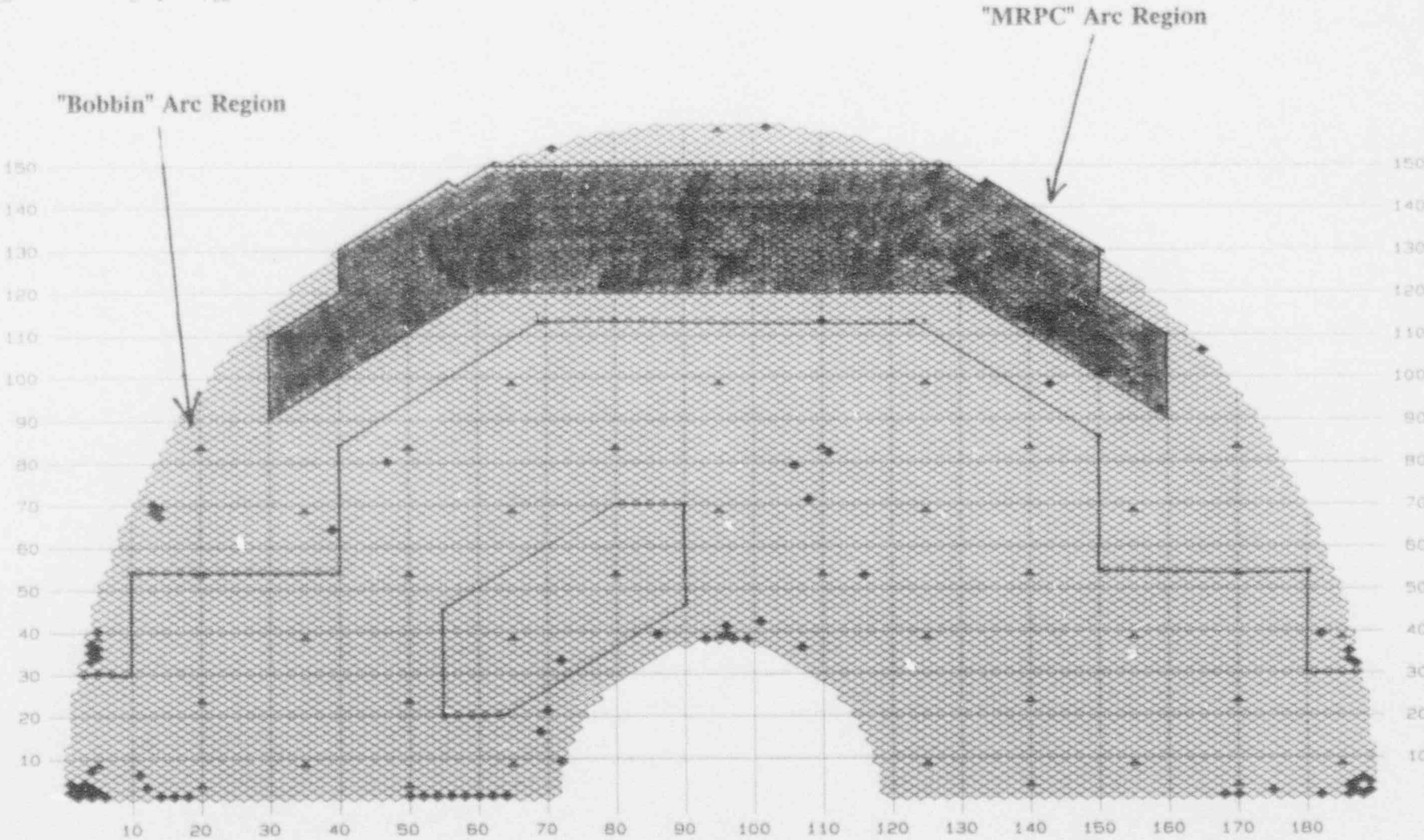
10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 11

Percent: PLG

STAYS

PLUGGED 0 ◆ PLG 74 ◆



CONAM NUCLEAR, INC. BW

V. STEAM GENERATOR INSPECTION

The original scope of ECT inspection for the Unit 1 fourth refueling outage consisted of the following:

- An inspection of 100% of the tubing using the bobbin coil probe
- A 20 % sample of the top of the tube sheet (hot leg) and at the flow distribution baffle plate using the MRPC probe
- A sample inspection of the bobbin indications associated with the 08H through the first vertical support structure with the MRPC probe
- An MRPC inspection of approximately 1800 tubes from the 08H support through the first vertical support, referred to in this report as the "MRPC" arc, the area where almost all of the free-span axial indications in Unit 2 were located (see Figure V-1).
- An MRPC inspection sample of 500 tubes from the 08H support through the first vertical support in the remainder of the SG
- All non-quantifiable or distorted indications detected during the bobbin coil examinations were inspected with the MRPC probe
- All expansion transition areas with distorted non-quantifiable signals detected during bobbin coil examinations were inspected with the MRPC probe
- An MRPC inspection of all No Tube Expansions (NTEs) (condition where no tube expansion exists)

The scope of eddy current analysis was subsequently expanded to include:

- An MRPC inspection of 100% of the hot leg tubesheet expansion transition area
- A 20% sample of the cold leg tubesheet expansion transition zone in SG 12

The bases of the initial scope was to perform bobbin coil inspections to provide assurance that a widespread pattern of flaws did not exist, and to perform MRPC inspections for several known issues. These issues included inspection for tubesheet circumferential cracking noted elsewhere in the industry, inspection for lower support axial cracks noted in previous PVNGS outages, inspection for axial cracks in the area shown to be susceptible in the U2R4 outage, and inspection of a sample at high elevations to ensure defects do not exist outside the arc regions (see Figure V-1).

During this inspection no axial defects were noted in the areas inspected from the 08H to vertical support area of the steam generators. A total of 7 circumferential cracks were found at the hot leg tubesheet in SG 11, and 76 circumferential cracks were found at the hot leg tubesheet in SG 12. These are the final results after expanding the ECT scope. Tubesheet maps indicating the location of all circumferential cracks are included as Figures V-2 and V-3.

Table V-1 summarizes the OD/ID nature of the circumferential cracks as determined by MRPC analysis.

TABLE V-1 INITIATION SITE FOR CIRCUMFERENTIAL CRACKS		
	Steam Generator 11	Steam Generator 12
OD Initiated	2	37
ID Initiated	5	31
OD & ID Initiated	0	8

Of those cracks identified as OD, all but one occurred in tubes located in the sludge pile. Figures V-4 and V-5 show the location and depth of the sludge pile in both SGs. An UT evaluation was undertaken to compare lengths of indications found during ECT, compare whether the indications were ID or OD initiated, and to estimate the depth of the circumferential indications.

Due to the orientation of flaws in SG tubing, specifically axial and circumferential indications, it is necessary to use variously oriented ultrasonic transducers to disposition particular flaws. An axially oriented shear wave UT transducer is required to locate circumferentially oriented cracks. Conversely, to locate axial flaws it is necessary to employ a circumferentially oriented shear wave transducer. For determination of wall thickness and location of the expansion zone, a zero degree UT transducer is used. All eighteen of the tubes examined by UT were analyzed using a circ/axial shear wave probe head. Thirteen were run with a zero degree probe head. It should also be noted that the UT examination with the axially oriented transducer was used looking down.

A preliminary review of MRPC data at the hot leg tubesheet of SG 12 resulted in a selection of 17 tubes as UT candidates for circumferential crack inspection. The selection criteria included:

- Single circumferential indications greater than one inch in circumferential length.
- The summation of multiple circumferential indications in a tube is greater than 1 inch in circumferential length.
- Top of tubesheet SVIs.

The UT and ECT examination results are listed in Table V-2 (for the UT sample). The depth of sludge in 1992 and 1993 at the tube location is also listed in the table.

The ID/OD comparison resulted in one tube having an indication classified as ID initiated using the UT technique and classified as OD using ECT analysis. With the exception of that tube, the remaining ID/OD comparisons were consistent. The majority of the ECT data length dimensions were conservative when compared to the UT length dimensions.

One additional tube (R122C101) was examined by UT at an SVI location 0.58 inches above the batwing (as described in Section IV).

The disposition of volumetric indications at PVNGS is based upon location and defect growth. All volumetric indications at support locations are considered wear and are evaluated to the established PVNGS plugging criteria. Freespan or tubesheet volumetric indications (SVIs) are evaluated separately by determining if a change is in eddy current signal has occurred over previous operating cycles. SVIs which have not changed are typically classified as baseline indications (BLI) or manufacturing buff marks (MBM). Generally, BLIs are ID marks whereas MBM indications are OD marks. For volumetric indications which are freespan and/or are at the top of the tubesheet, and are considered new or changed indications, PVNGS elected to plug these defects regardless of depth. Additionally a small number of tubes with MBM indications were preventatively plugged if the manufacturers mark could partially mask a future indication or was associated with a deposit in the arc region. The disposition of all SVIs which were plugged in Unit 1 are summarized in Tables VIII-1 and VIII-2. Volumetric indications associated with the arc regions are identified in Tables XI-5, XI-6, and XI-7 in the Appendices.

TABLE V-2
COMPARISON OF MRPC AND ULTRASONIC TEST RESULTS
FOR UNIT 1 STEAM GENERATOR 12

		ULTRASONIC			EDDY CURRENT (MRPC)		SLUDGE	
Tube	Location	ID/OD	Length (inches)	% TW	ID/OD	Length (inches)	Depth 92 (inches)	Depth 93 (inches)
23-58	TSH	ID	0.710	40	ID	1.32	0.94	1.81
23-60	TSH	ID	0.850	90	ID	0.99	0.96	1.62
25-60	TSH	OD ID	0.380 0.840	45 75	OD ID	0.26 1.22	1.18	1.90
35-60	TSH	ID	0.975* 1.50**	100	ID ID	1.06 0.25	0.81	1.45
47-62	TSH	OD ID ID	0.117 0.168 0.081	30 50 20	ID	1.15	0.44	1.21
43-66 †	TSH	ID	0.128	50	ID OD	0.45 0.27	N/A	1.87
54-71 †	TSH	ID	0.864* 1.44**	100	ID	1.67	0.63	1.84
54-73 †	TSH	ID	0.182* 2.08**	100	ID ID ID ID	0.51 0.30 0.43 0.38	1.07	1.84
54-75 †	TSH	ID	1.560* 1.96**	100	ID OD	2.01 0.28	0.90	1.52
62-75 †	TSH	OD OD OD	0.091 0.410 0.064	25 30 25	OD OD	0.94 0.28	0.71	1.42
64-75 †	TSH	ID	0.215* 1.30**	60	OD	0.30	0.63	1.31
49-75 †	TSH	ID	0.563* 0.85**	90	ID OD	0.50 SVI	0.62	1.60
53-76 †	TSH	ID	0.151* 1.30**	50	ID OD	0.32 0.18	N/A	1.36
60-77 †	TSH	OD	0.370	75	ID OD	0.68 0.57	0.77	1.59
51-78 †	TSH	No Indication	No Indication	No Indication	ID OD	0.41 SVI	0.82	1.52
46-79 †	TSH	ID	0.540* 1.57**	70	ID	1.33	N/A	1.35
65-84 †	TSH	OD	0.110	20	OD OD OD	0.43 0.36 0.22	0.71	1.65
122-101	BW1+0.06	OD	1.015	40	OD	0.25	N/A	N/A

* Multiple circumferential indications found. Length represents longest indication found.

** Length represents combined extent of multiple circumferential indications found.

† Possible IGA/deposits called with zero degree UT examination.

FIGURE V-1

Palo Verde Steam Generator Tube Map
Areas of Tube Cracks

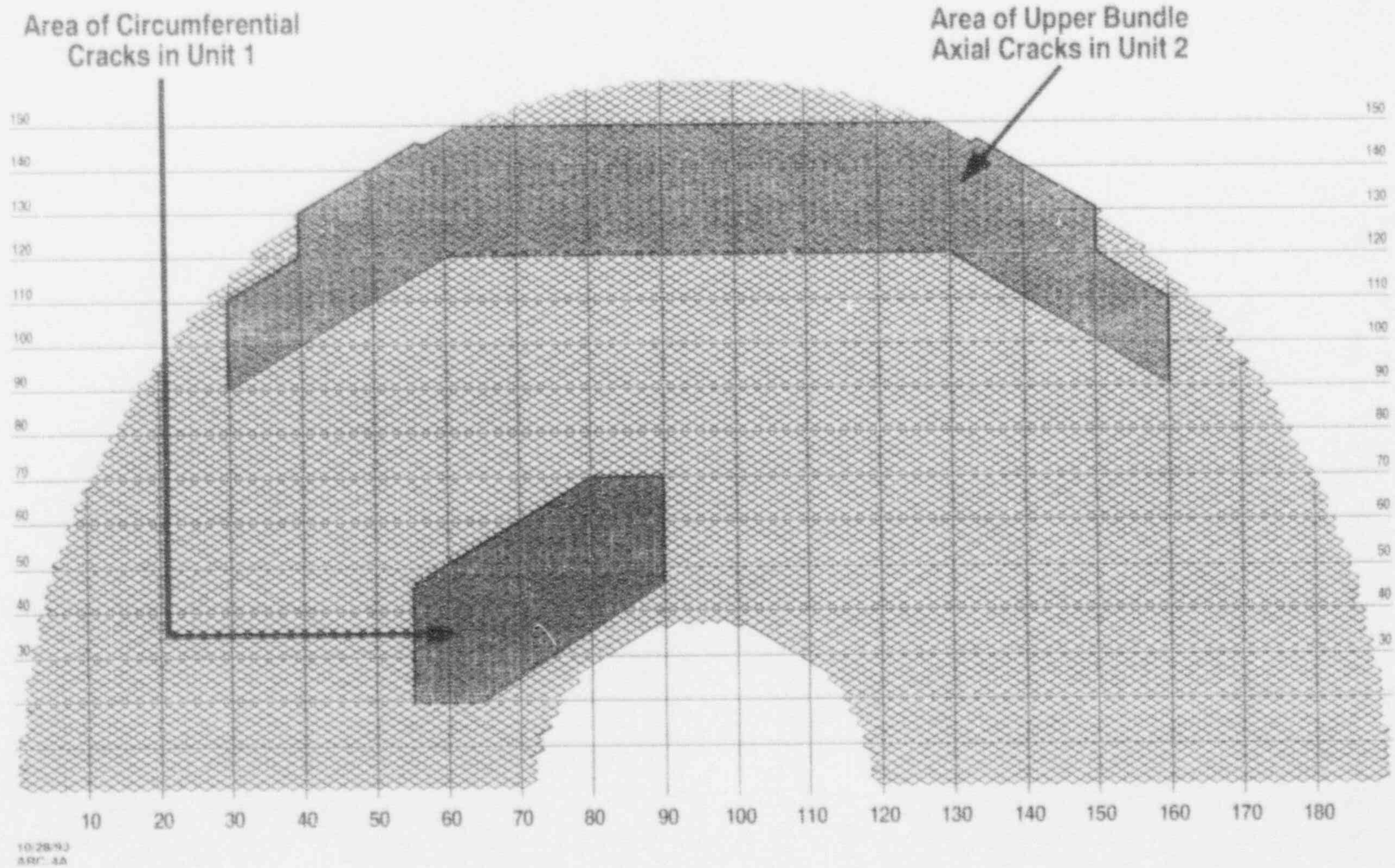


FIGURE V-2, CIRCUMFERENTIAL INDICATIONS, SG 11

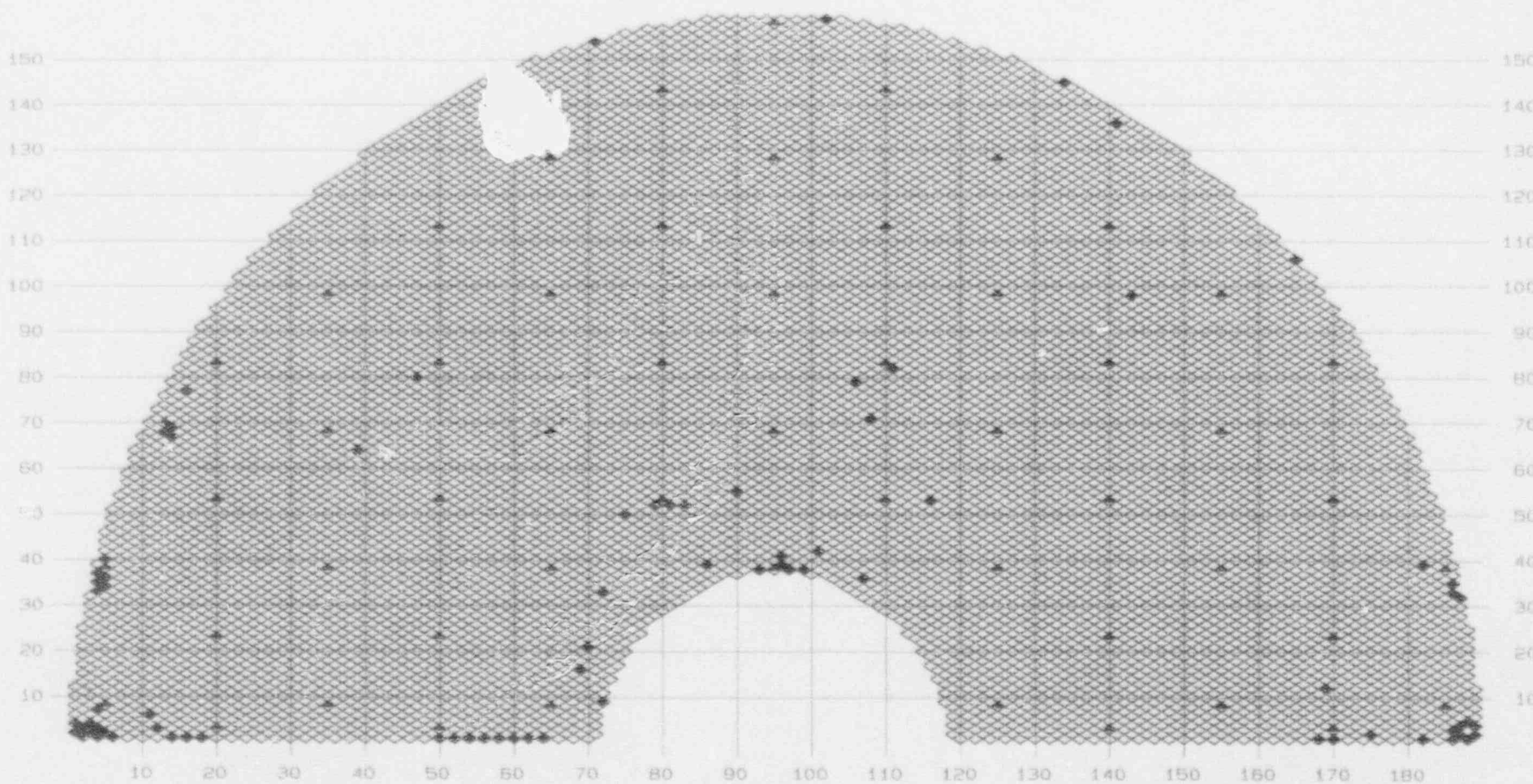
10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 11
OUTAGE DATA SET : CURRENT
Percent: MCI, SCI

DATE: 10/24/93
TIME: 10:50:47

STAYS

PLUGGED 74 ◆ MCI 1 ◆ SCI 6 ◆



CONAM NUCLEAR, INC. BW

FIGURE V-3, CIRCUMFERENTIAL INDICATIONS, SG 12

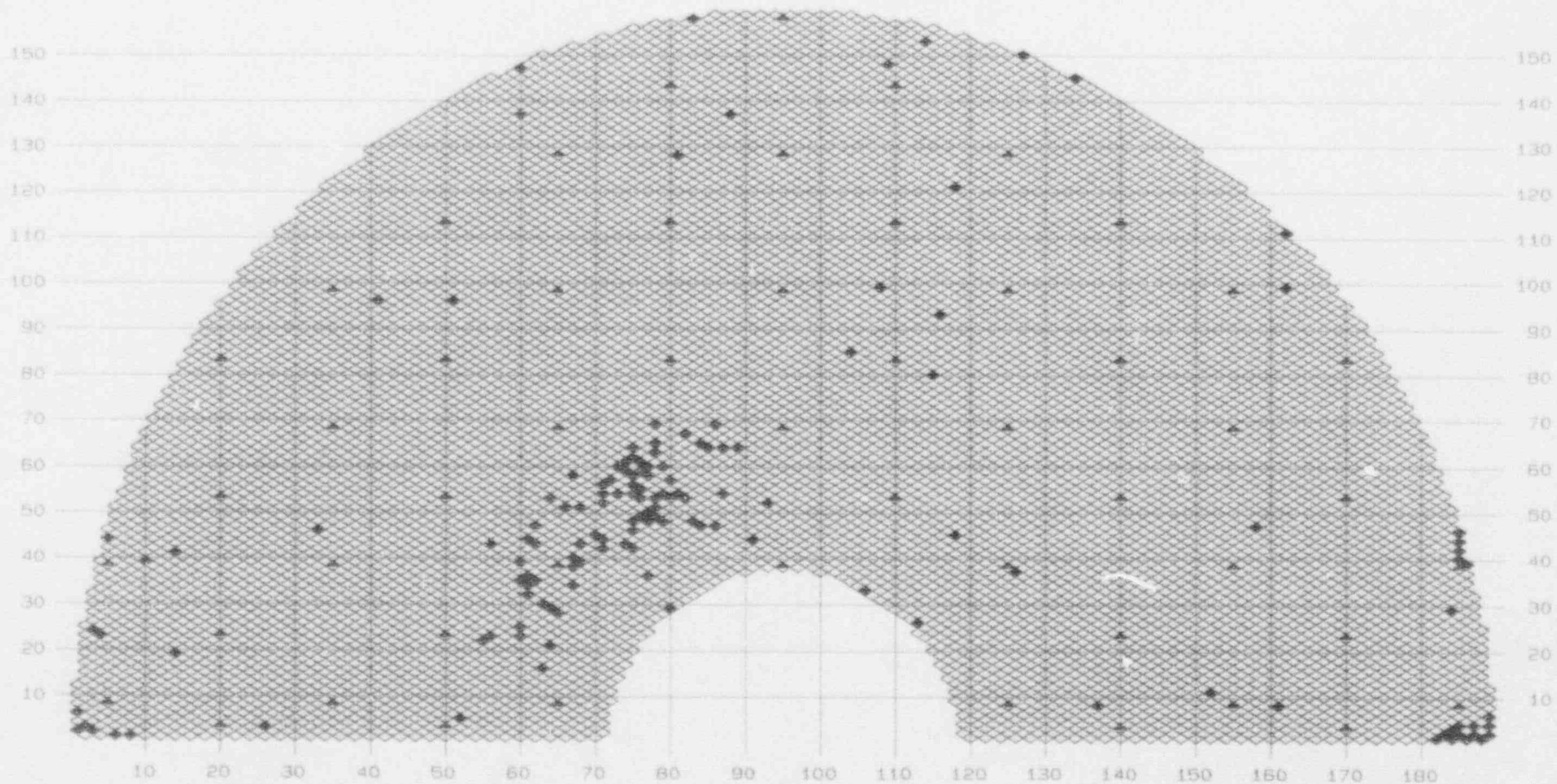
10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 12
OUTAGE DATA SET : CURRENT
Percent: MCI,SCI

DATE: 10/26/93
TIME: 15:21:07

STAYS ▲

PLUGGED 67 ◆ MCI 2 ◆ SCI 74 ◆



CONAM NUCLEAR, INC. BW

FIGURE V-4, SLUDGE LOCATION AND DEPTH, SG 11

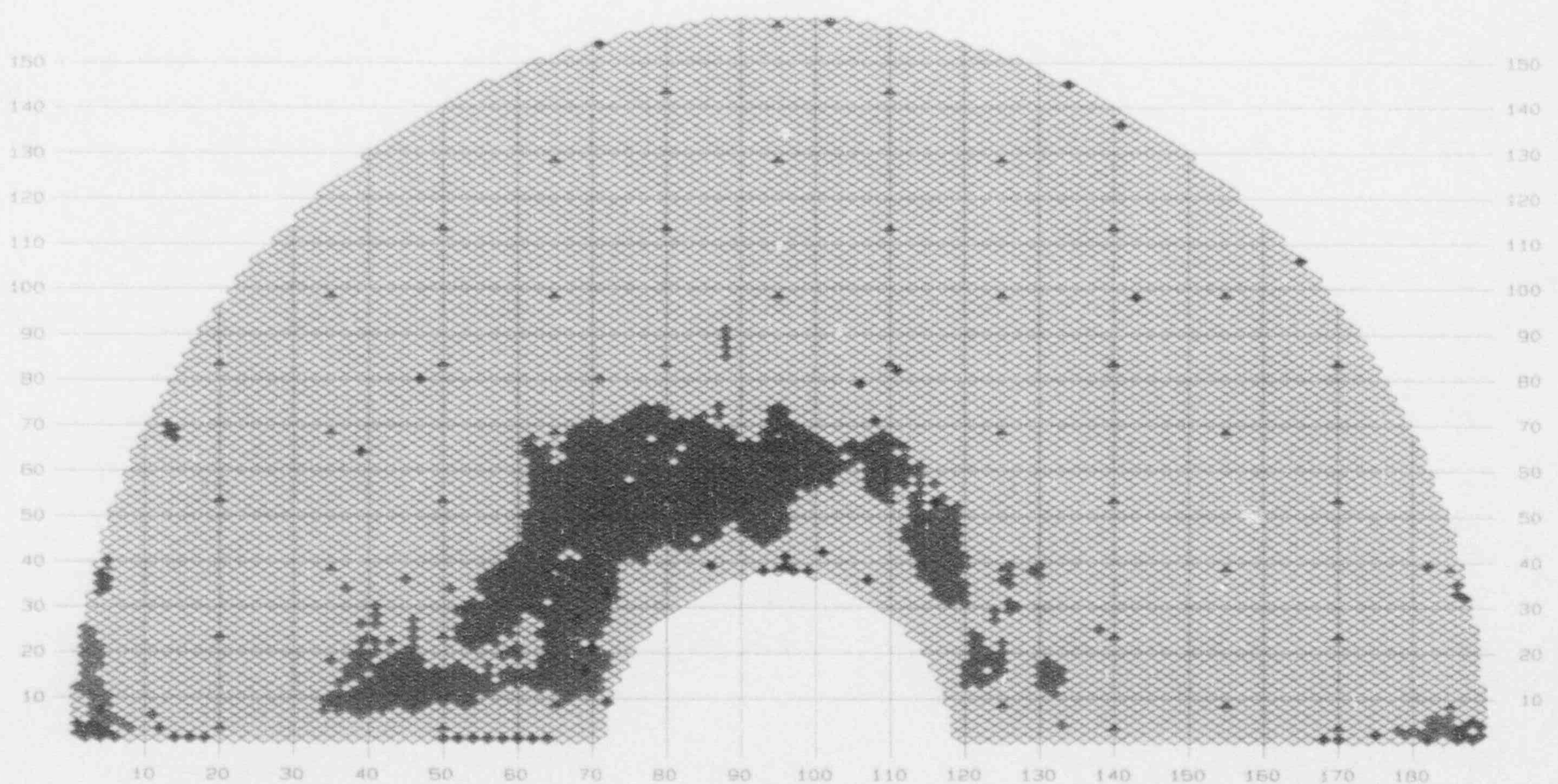
10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 11
OUTAGE DATA SET : CURRENT
Indication Location: TSH 0.00 to TSH +10.00 AND Percent: SLG

DATE: 10/22/93
TIME: 11:48:48

STAYS ▲

PLUGGED 74 ◆ 0.0 in - 1.0 in 541 ◆ 1.1 in - 1.5 in 414 ◆ 1.6 in - 2.0 in 60 ◆ 2.1 in - 2.5 in 1 ◆ > 2.5 in 0 x



CONAM NUCLEAR, INC. BW

FIGURE V-5, SLUDGE LOCATION AND DEPTH, SG 12

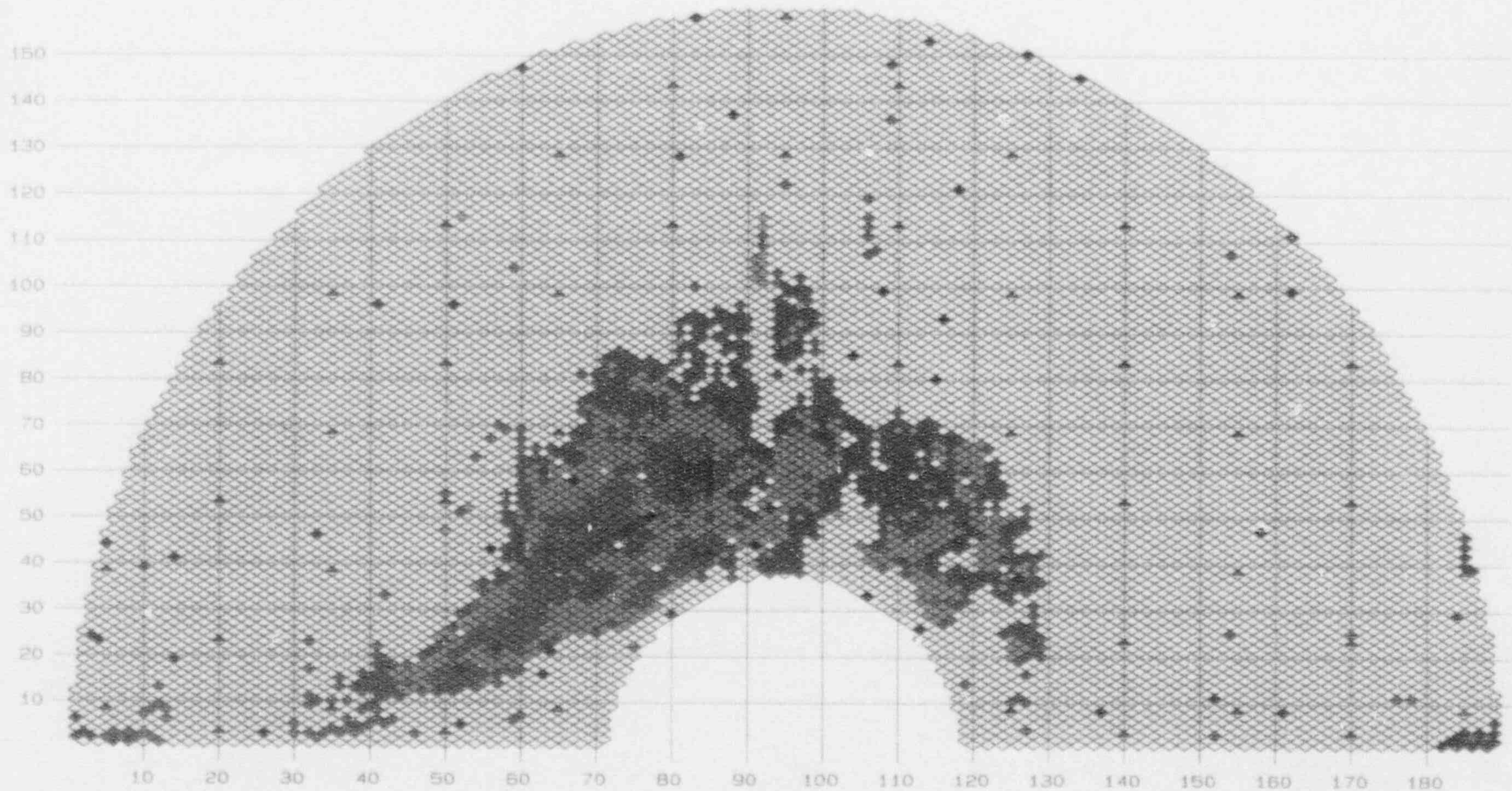
10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 12
OUTAGE DATA SET : CURRENT
Indication Location: TSH 0.00 to TSH +10.00 AND Percent: SLG

DATE: 10/22/93
TIME: 11:36:38

STAYS ▲

PLUGGED 67 ◆ 0.0 in - 1.0 in 698 ◆ 1.1 in - 1.5 in 610 ◆ 1.6 in - 2.0 in 292 ◆ 2.1 in - 2.5 in 26 ◆ > 2.5 in 1 ◆



PLP ANALYSIS

CONAM NUCLEAR, INC. BW

VI. ROOT CAUSE CIRCUMFERENTIAL CRACKING

A. Scope of Mechanism

Circumferential cracking of Unit 1 steam generator tubes at the tubesheet has been detected by eddy current examination during the fourth refueling outage. While some axially oriented tubesheet flaws were detected, the majority are circumferentially oriented similar to those found at other Combustion Engineering plants. The cracks are located at the hot leg top of tubesheet bundle, with the highest concentration of defects occurring in the low-velocity flow area near the center of the tube sheet. In this area, commonly referred to as the "kidney bean" (see Figure VI-1), particles present in the secondary fluid tend to deposit and accumulate. Ultrasonic testing has confirmed that the circumferential cracks originate in some cases from the inside diameter, while in other cases, from the outside diameter. The cracks are located slightly above the upper surface of the tube sheet, in the tube-expansion transition zone. In general, the elevation of the ID initiated cracks is slightly higher than the elevation for the OD cracks due to the stress pattern in the expansion transition.

B. Inside Diameter Initiated Cracks

Based on physical location and industry experience it was concluded that the defects initiating on the inside diameter are PWSCC. This position is supported by a lack of any primary system contaminant excursion events. PWSCC results from a combination of residual and applied stresses, a susceptible microstructure, and a suitable environment. Temperature is the most critical environmental factor in PWSCC, with an increase in temperature resulting in a decrease in the time to cracking (Reference 6 and 17). The driving force for PWSCC is therefore the residual stresses in the tube transition zone from expanded to unexpanded, along with the high primary coolant temperature.

The transportability of PWSCC from unit to unit, based solely upon operating primary temperature, would indicate all three units would expect to experience PWSCC in the same time frame. Studies by Aptech Engineering and EPRI (see Figure VI-2 derived from EPRI NP-7198-S), based upon cumulative operating time, predict the onset of PWSCC after approximately four cycles of operation. Other factors may, however, influence the initiation of PWSCC. The more sensitive the material is to PWSCC and the higher the tube temperature due to the isolating effects of sludge deposits, the more rapidly the cracking appears. Thus, the worst-case tubes would experience PWSCC earlier than the majority of the tubes.

Flow differences which may lead to differences in sludge characteristics, such as deposit chemistry and sludge depth and extent, can vary greatly from one steam generator to the next. The effect of different flow and sludge characteristics can have an effect on the insulating properties of the tubing and on the rate of PWSCC.

Based upon the potential differences in tubing microstructure, flow, sludge characteristics and residual stresses, a direct correlation of PWSCC at Unit 1 cannot be readily assumed with Unit 2 or Unit 3. These factors can account for the fact that Unit 1 has demonstrated this corrosion mechanism at this time.

C. Outside Diameter Initiated Cracks

While the degree of PWSCC is limited to the effects of stress, material microstructure and temperature, the mechanisms contributing to outside diameter circumferential cracking can be more complex. The additional contributing factors for OD cracking, as observed throughout the industry, include chemical aggravators such as caustic or acidic conditions, accelerators such as lead, copper and sulfur species, electrochemical potential, and the ingress of contaminants such as oxygen and polisher resins.

Circumferential and axial outside diameter cracks at the top of the tubesheet were observed at Palo Verde Unit 1. As is the case for the tubes exhibiting PWSCC, the circumferential defects are predominantly located within the hot leg kidney bean area, with the cracks originating within the tube expansion transition zone near the top of the tubesheet. The axial cracks were predominantly located in tubes with incomplete or nonexistent tubesheet expansion. The axial orientation of these defects would be expected since the residual stresses of a roll transition are not present and only applied hoop stresses define the stress field.

A review of operating chemistry data, shutdown hideout return chemistry data and sludge sample data has been conducted. This review of Unit 1 chemistry has identified only one significant chemistry excursion. That event, a condenser tube rupture occurred in December of 1985. SG pH values dropped below 3 and chloride, sulfate, and sodium values peaked at 35 ppm, 27 ppm, and 14 ppm respectively. The plant was shutdown and pH was restored to normal values within 24 hours. The other units have not experienced a condenser tube rupture which resulted in significantly degraded chemistry conditions.

Due to the short duration of this excursion it is unlikely that this single event would account for the presence of OD cracks in Unit 1. It is more likely that the defects are slow in initiation and growth until sufficient attack has occurred to be detectable by eddy current. Based upon a historical review of operating chemistry data and hideout return chemistry data, the most likely contributor to the IGSCC is caustic crevice chemistry. During periods of full flow condensate polishing (1985 through the beginning of 1993), Palo Verde secondary water has been found to be alkaline-forming with concentration of caustic species in flow restricted areas such as steam generator crevices and under the sludge pile. The free caustic formed when feedwater concentrates at the superheated tube wall can corrode the Alloy 600 tubes. The degree of cracking is a function of all the contributing factors outlined above.

Note that analysis of Unit 2 pulled tube samples with flow distribution plate (01H) axial cracks were examined during the summer of 1993. The results confirmed classic caustic OD initiated IGSCC in the lower region of the tube bundle.

With respect to hideout return chemistry data, all three units have operated with similar chemical environments. MULTEQ pH predictions have averaged between 10.20 and 10.35 in all three units during 1991 and 1992. Prior to 1991 a formal hideout return program was not in place however, peak concentrations of sodium, chloride and sulfate indicate similar operating conditions. Due to corrective actions begun in late 1992, Unit 1 and 3 appear to be operating with crevice chemistry which is near neutral or acidic. MULTEQ analysis provides pH values less than 3.0 in Unit 1 (September 1993 shutdown) and less than 5 in Unit 3 (September 1993 downpower). Unit 2 crevice pH conditions are being evaluated. Based upon past operating and shutdown chemistry at all three units, the possibility exists for caustic induced IGSCC in all Palo Verde units.

A comparison of sludge samples obtained from Unit 1 during the third refueling outage and the current refueling outage (U1R4) has not shown a likely contributor to IGSCC. Lead concentrations were below the levels typically observed at other utilities which have identified lead as a contributor to ODSCC. Bugey 2 and 3 have sludge lead levels over 500 ppm (Reference 18). Copper levels are well below those observed at other CE facilities with ODSCC (over 50,000 ppm at ANO 2 and over 100,000 ppm at SONGS 2). Sodium, sulfur and chloride levels are considered low. However these species are volatile and therefore the sludge analysis may not be representative of operating chemistry.

TABLE VI-1

UNIT 1 SG SLUDGE ANALYSIS

Analyte	U1R3 Flow Distribution Plate	U1R4 Tubesheet	U1R4 Flow Distribution Plate
Lead	78 ppm	98 ppm	N/A
Copper	106 ppm	1214 ppm	74 ppm
Sodium	230 ppm	22 ppm	N/A
Chloride	30 ppm	< 9 ppm	N/A
Sulfur	< 50 ppm as SO_3	< 9 ppm as SO_4	N/A
Iron	> 98%	N/A	N/A

Note: All analyses conducted during U1R3 were from a flow distribution plate sample. The U1R4 analyses were conducted on tubesheet samples with the exception of copper which was performed on both the tubesheet and flow distribution plate samples.

Comparing the concentration of contaminants in the sample taken from the Unit 1 tubesheet to typical industry values, it does not appear that a specific aggravator in the sludge led to the ODSCC observed.

An ingress of resin has been documented for Unit 2 (Reference 1) however, there is no evidence to suggest a significant ingress of resin has occurred in Unit 1. A secondary side inspection in Unit 2 identified resin beads on the SG can deck, however a similar inspection in Unit 1 revealed no visual evidence of resin. Therefore, it is doubtful that resin ingress contributed to the circumferential cracking in Unit 1.

The extent to which elevated electrochemical potential (ECP) may have impacted the cracking is an unknown at Palo Verde, as it is at most operating plants. It is likely that elevated ECP is not a major contributor due to 1) very low ingress of oxygen historically, 2) a large excess of hydrazine (most recently Palo Verde has complied with the 100 ppb hydrazine EPRI guideline) and 3) and a nearly copper-free secondary system.

Based upon the hot leg temperature, sludge characteristics, residual stresses, and chemical environment, the presence of OD defects at the tubesheet are not unexpected. The crack growth rates do not indicate an accelerated condition which would result in exceeding the structural limits of RG 1.121.

D. Summary

The root cause effort attempted to examine the material, stress and environment in the area where circumferential cracks were found. Metallurgical data on the cracked tubes is not available, so it is speculative as to whether these tubes have a substandard microstructure that accounts for early crack initiation. While Unit 2 metallurgical analysis showed that substandard microstructure can occur, the correlation of crack location to sludge would indicate that microstructure is not the driving force behind circumferential cracks. Residual stress, caused by slight overexplansion at the top of tubesheet, can account for the pattern of ID cracks discovered. The chemical environment in the sludge is not anomalous based upon the chemical analysis of the sludge. It is concluded that the high operating temperature at PVNGS is the primary root cause contributor with some contribution from the presence of sludge.

FIGURE VI-1

Palo Verde Steam Generator Tube Map
Areas of Tube Cracks

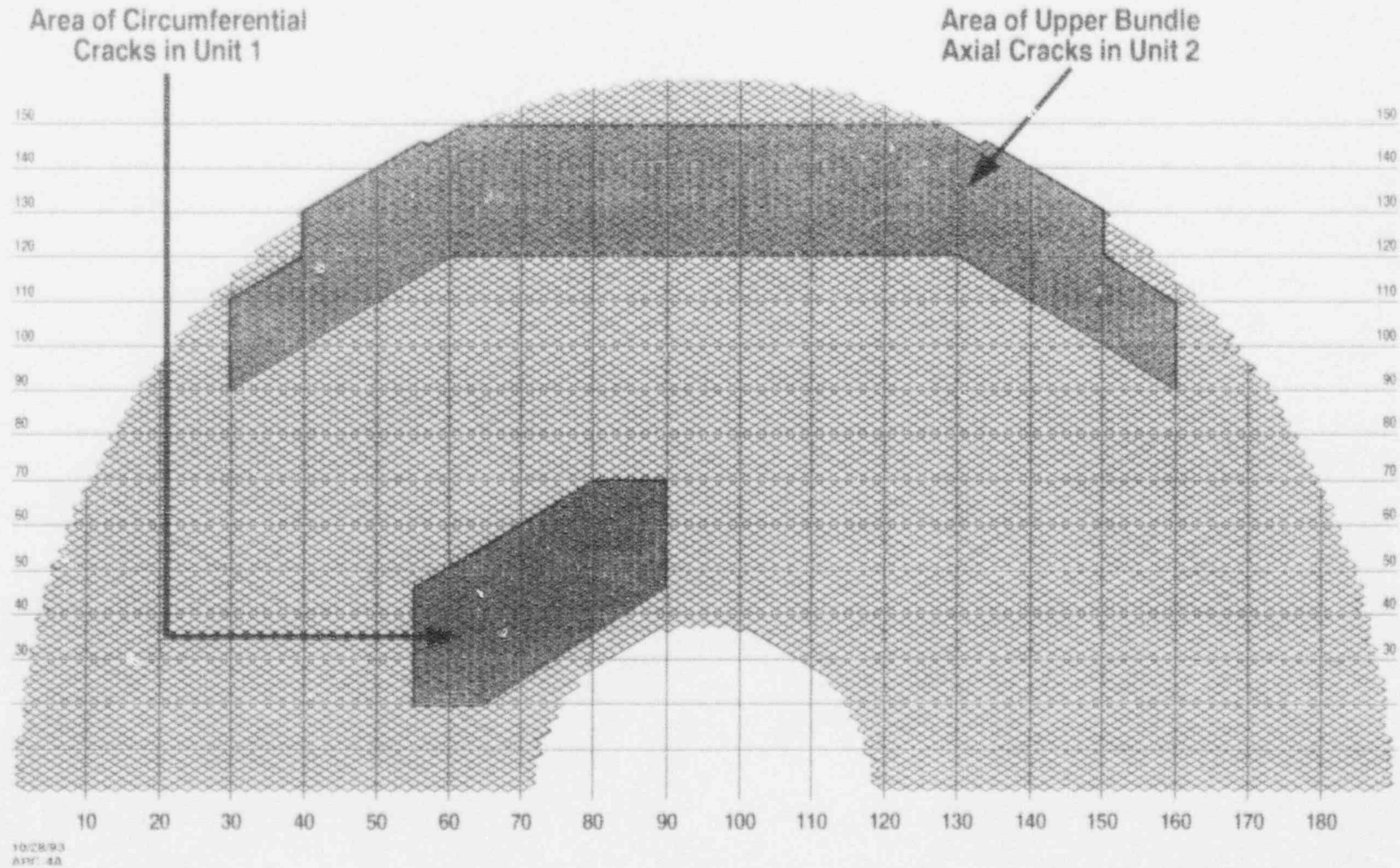
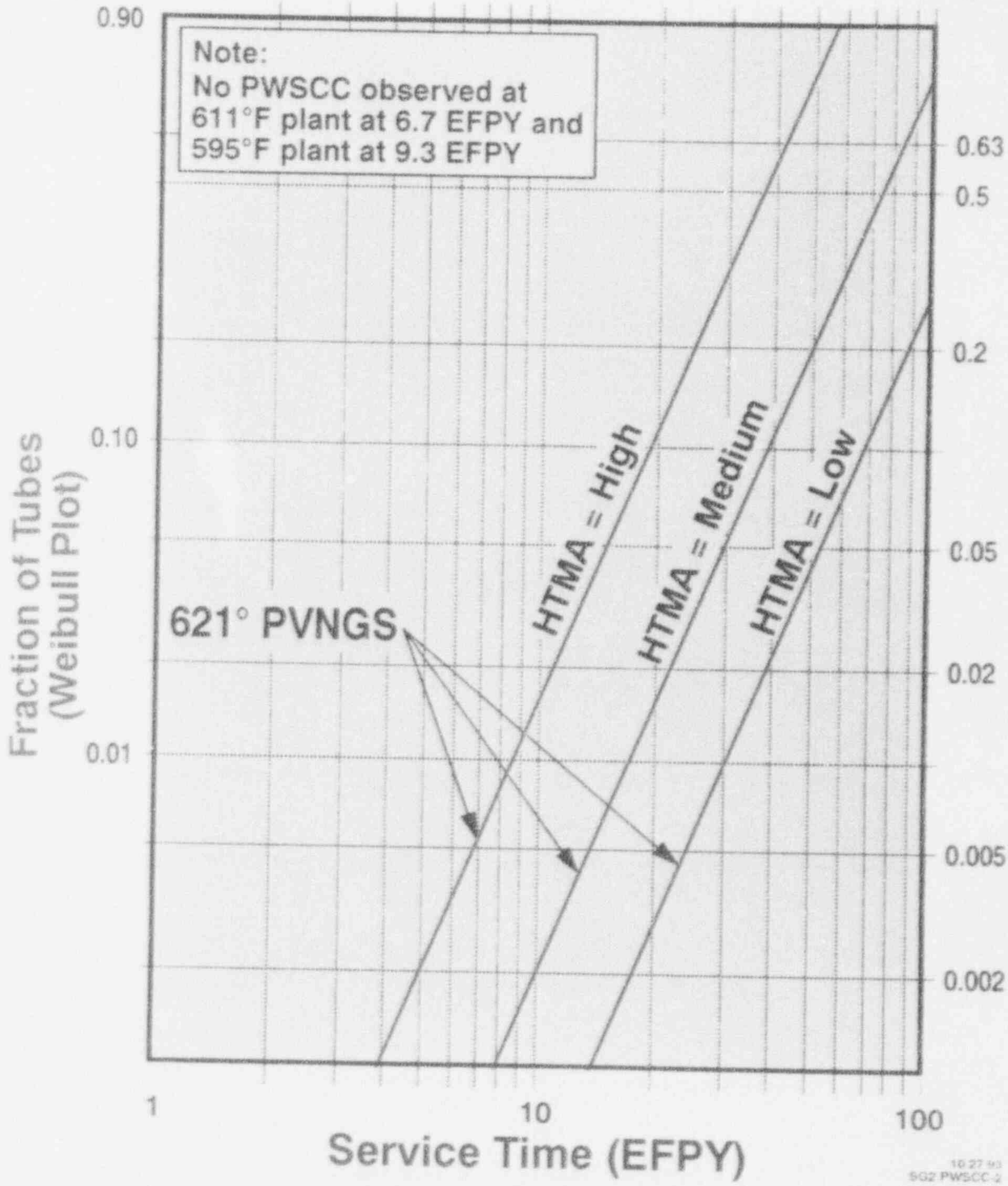


FIGURE VI-2

Predicted PWSCC at Explosive Transitions HTMA Tubing



10 27 93
SG2 PWSCC-2

VII. REGULATORY GUIDE 1.121 EVALUATION

NRC RG 1.121 provides the requirements for evaluating the structural integrity of degraded steam generator tubing.The requirements are designed to maintain specific margins for degraded tubing against rupture. An evaluation must be performed to ensure that the safety margins specified by the RG are not violated during the next operating cycle. The evaluation of the circumferential cracks at the top of the tubesheet in the Unit 1 steam generators was performed by demonstrating that the safety margins were maintained over the previous operating cycle and then determining that degradation during the upcoming cycle should be no worse than the previous cycle.

To determine whether the required safety margins were maintained over the previous cycle, a structural evaluation was performed to determine the maximum crack size that would be expected to meet the required safety margins. Eddy current test results were then reviewed to identify all cracks that exceeded or approached the calculated allowable crack size. These cracks were then examined by ultrasonic (UT) techniques to provide further characterization of the defects. Finally, the largest defects were in-situ pressure tested at the pressure corresponding to the required safety margins specified in RG 1.121. All the tubes tested passed the pressurization test, indicating that the required safety margins had been maintained over the previous operating cycle in Unit 1.

A. Structural Evaluation

1. Circumferential Cracks

The tube integrity with postulated circumferential flaws was evaluated to the requirements of RG 1.121. These requirements are designed to maintain specific safety margins for degraded tubing against potential rupture during normal plant operation and postulated accident conditions. The recommendation of RG 1.121 specify that steam generator tubes should have a safety factor against failure by bursting during normal operation of not less than 3. The specified margin for accident conditions is taken to be equal to 1.4.

Because the flaw orientation is circumferential, the principal stress affecting tube integrity will be the axial stress resulting from the differential pressure between the primary and secondary side of the steam generator tubing. Therefore, the axial stress will be bounded by the following loadings:

	Normal Operating	Accident (MSLB)
Primary (psia)	2250	2400
Secondary (psia)	1070	0
Differential Pressure (psia)	1180	2400
Safety Margin	3	1.4
Limiting Differential Pressure (psia)	3540	3360

Therefore, in order to meet the required safety margins specified in RG 1.121, the degraded tubing must be capable of withstanding a differential pressure of 3540 psid.

The burst condition of a tube with a circumferential through wall flaw over some circumferential extent was determined from a net section collapse formula developed by Belgatom (EPRI NP-6626-SD "Belgian Approach to Steam Generator Tube Plugging for Primary Water Stress Corrosion Cracking") which predicts tube rupture when the local axial stress reaches the material's flow stress and considers either an unsupported tube or a tube with a lateral support such as would be provided by the flow distribution plate. Using this correlation, the maximum allowable circumferential crack length (assuming 100% through wall over the entire circumferential extent of the crack) can be determined as shown in Figure VII-1. As illustrated, based on a limiting differential pressure of 3540 psi, a crack of up to approximately 280° (or 1.6 inches based on inside diameter) would be expected to maintain the required safety margin. This conservative approach takes no credit for partial depth crack extent or ligaments which would be expected to be present based on typical stress corrosion crack morphology. Figure VII -1 also provides burst pressure data for a tube with no lateral support and using classic net axial stress area (axial force limit) methods.

2. Axial Cracks

The integrity of tubes with OD axial cracks at the tubesheet was also evaluated to the requirements of RG 1.121. The structural analysis (Reference 1) for the Unit 2 SG tube rupture event was used as a basis for the evaluation. A summary of the crack length, depth, and location is given in Tables VII-1 and VII-2. Based on the results of the analysis, the maximum allowable throughwall defect is 0.787 inches in length. Where no ECT depth call was made, the depth was assumed to be 100% throughwall. The longest defect meeting this assumption was 0.66 inches in length and is bounded by the analysis. The largest flaw with both an ECT depth and length characterization is tube R93C120 with an 86% throughwall extent and 0.76 inches in length and is also bounded by the structural analysis. Additionally, with one exception, the OD axial cracks found at the tubesheet were within the confines of the tubesheet structural support and would not be candidates for axial fishmouth ruptures based on the small diametrical clearance (0.004 inches). The defect in tube R46C35 was located at TSH+0.15 however it was only 0.17 inches in length. Finally, a single ID initiated axial defect was found within the tubesheet (TEH+1.51) in a tube which was expanded. The defect was 1.03 inches in length at 79% throughwall. This defect is not considered to exceed RG 1.121 guidelines since structural integrity is maintained by the tubesheet.

3. Single Volumetric Indications

The RG 1.121 structural requirements for volumetric indications are based on wall thinning analysis performed by ABB-CE for wear type defects. A 63% throughwall extent has been justified by this analysis (Reference 20). The deepest SVI sized by bobbin ECT analysis was 59% throughwall and therefore is bounded by the structural analysis.

B. ECT and UT Results

The MRPC eddy current probe was used to size and characterize the indications. Due to the difficulty in obtaining a reliable depth call with MRPC, only circumferential extents (lengths) were assigned to each defect. Conservative guidelines for determining the circumferential extent were used to ensure the cracks were not undersized. Since depth calls were not made, all cracks were conservatively assumed to be 100% through wall over the entire circumferential extent of the flaw. This very conservative assumption allows direct comparison with the allowable crack size determined in section VII.A. The comparison identified 3 tubes which potentially exceeded or approached the allowable crack size of 1.6 inches. These indications were subsequently examined by UT to further characterize the defect and to obtain a measure of the crack depths. Additionally, all tubes with circumferential indications greater than 1 inch or multiple indications with the sum of the indications greater than 1 inch were examined by UT to obtain characterization of all larger cracks and to provide a comparison between MRPC and UT results. Other tubes with smaller indications were also examined for further characterization. Based on this criteria, the following tubes with circumferential indications were inspected

Table VII-3
SG 12 Tubes Examined by UT

Row/Col	MRPC Length (in)	Max UT Depth (%)
54/75	2.01	100
54/73	1.9*	100
54/71	1.67	100
35/60	1.31*	100
48/79	1.33	70
23/56	1.32	40
23/60	0.99	90
25/60	1.22	75
47/62	1.15	50
43/68	0.45	50
62/75	1.12*	30
64/75	0.3	60
49/76	0.5	90
53/76	0.32	50
60/77	0.57	75
51/78	0.41	N/A
65/84	1.01*	20

* Indicates summation of multiple indications at the same axial location. Some tubes exhibit both ID and OD indications. The indications do not occur at the same axial location, therefore are not summed together.

C. **In-Situ Pressure Test**

Based on the MRPC and UT examinations, several cracks appeared to approach or exceed the conservative maximum allowable crack length of 1.6 inches and potentially did not maintain the required safety margins over the previous operating cycle. Therefore, 5 tubes were selected to be in-situ pressure tested for final determination as to whether the required safety margins had been maintained. These cracks were chosen as being the bounding, or worst case cracks, based on length or potential through wall depth. All 5 tubes were pressurized to 3900 psia, based on the limiting differential pressure of 3540 psi adjusted for room temperature conditions, and held for approximately 8 minutes. All 5 tubes, as tabulated below, were successfully pressure tested to 3900 psi, indicating the required safety margins against bursting were maintained.

Row/Col	Pass/Fail
54/75	Pass
54/73	Pass
54/71	Pass
35/60	Pass (leak)
48/79	Pass

As indicated, tube 35/60 developed a small leak during the pressurization test. This was not unexpected since the UT examination indicated potential through wall degradation over a short circumferential extent of the defect. The test was conducted by bringing the pressure up in increments and then holding pressure at 1000, 2000, 3000, and 3900 psi. Tube 35/60 indicated very small leakage at the 2000 psi plateau. At 3000 psi (greater than MSLB pressure), leakage increased to approximately 16 gpd. Leakage of this small of magnitude at 3000 psi indicates the actual through wall circumferential extent of the crack to be extremely short. At 3900 psi, leakage was measured at approximately 90 gpd, essentially equal to the maximum capacity of the hydrotest pump. However, pressure was maintained at or around 3900 psi for approximately 8 minutes before the test was terminated, indicating the structural integrity of the tube was maintained. After completing the pressure test on all 5 tubes, 35/60 was retested to ensure the validity of the first test. In the second test, slight leakage occurred at 1000 psi. and increased at the 2000 and 3000 psi plateaus. While attempting to raise pressure up to 3900 psi, leakage exceeded the 90 gpd capacity of the hydropump and only approximately 3500 psi was achieved. However, pressure was maintained at 3500 psi indicating no change to the gross structural integrity of the tube. In fact, a small increase in leakage during a second pressure test is entirely consistent with laboratory experience with tube burst tests, wherein leakage is typically observed to occur at a lower value and at an increased rate during a second test. This is due to the tube swelling during the first test causing a through wall crack to open slightly. Laboratory experience indicates this does not represent a decrease in the burst strength of the tube. Therefore, APS has concluded that the test data indicates successful capability to withstand 3 times normal operating pressure without bursting as required by RG 1.121. All 5 tubes were re-inspected by MRPC after completion of the in-situ pressure test. None of the tubes, including 35/60, showed any appreciable change in the eddy current signals, further evidence that the burst capability of the tubes was not exceeded.

D. Conclusion

Based upon the assumption that in situ pressure testing was performed on the "worst case" tubes, all the tubes with circumferential defects at the top of the tubesheet have maintained the required safety margins specified over the previous operating cycle. Accordingly, it is concluded that the safety margins will be maintained over the upcoming cycle.

The largest cracks were PWSCC-initiated ID defects. The occurrence of PWSCC is dictated primarily by temperature and stress and, accordingly, industry experience indicates a controlled rate of progression. Growth rates observed within the industry have not typically indicated a damage progression from undetectable to RG 1.121 violation in one operating cycle. Since 100% of the hot leg tubesheet transition area has been examined by MRPC, and all tubes with a circumferential indication have been removed from service, it is expected that inspection results at the end of the next operating cycle will show a reduced progression rate in terms of size of defects discovered without any corrective actions. The mitigating actions planned should reduce the progression rate even further.

The circumferential OD indications are considered to be classical sludge pile ODSCC. These defects were typically much smaller than the largest ID indications, none of which were potential challenges to the structural integrity of the tube. Mitigative actions consisting of reduced temperature, sludge lancing, implementation of boric acid treatment, molar ratio control, and elevated secondary plant pH will be implemented during the next cycle. Since ODSCC growth rates are influenced by the sludge pile environment, these mitigative actions are expected to slow the rate of progression of this mechanism.

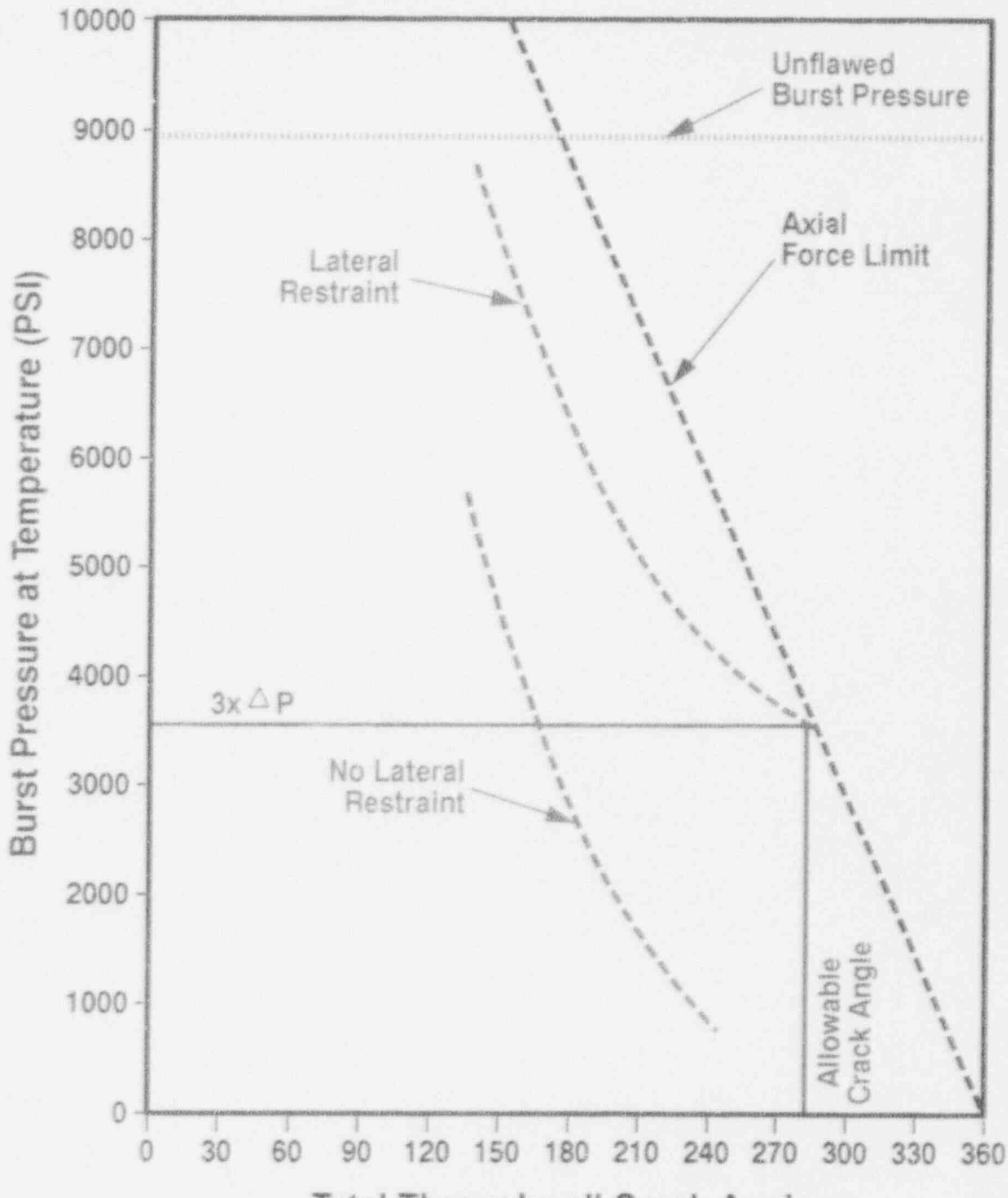
APS will operate Unit 1 at reduced temperature as much as practical to slow the rate of progression of PWSCC and prevent IGSCC in the upper bundle arc region. Such an adjustment will also result in a lower secondary side steam pressure and consequently a larger normal operating differential pressure. This results in a slightly smaller allowable crack size. For example, if secondary side pressure is reduced to 970 psi, 3 times normal differential pressure would be increased to 3840 psi. Based on Figure VII-1, this would reduce the allowable through wall crack from 280° to approximately 270°. This negligible decrease in allowable flaw size would be more than compensated by the expected reduction in crack growth rate associated with the temperature reduction.

TABLE VII-1					
TUBESHEET AXIAL CRACKS, SG 11					
Row	Column	Location	Percent Through wall	Call	Length (inches)
49	10	TSH-1.36	N/Q	MAI	0.51
54	11	TSH-0.76	52%	MAI	0.48
62	21	TSH-0.70	59%	MAI	0.65
27	78	TSH-0.65	58%	SAI	1.00
33	84	TSH+1.51	79%	SAI	1.03
30	163	TSH-0.20	N/Q	SAI	0.19
56	181	TSH-0.99	N/Q	SAI	0.66

TABLE VII-2					
TUBESHEET AXIAL CRACKS, SG 12					
Row	Column	Location	Percent Through wall	Call	Length (inches)
23	6	TSH-1.15	N/Q	MAI	0.50
46	35	TSH+0.15	N/Q	SAI	0.17
87	72	TSH-0.83	86%	MAI	0.53
87	74	TSH-0.67	N/Q	MAI	0.28
28	111	TSH+0.50	N/Q	SAI	0.25
93	112	TSH-0.52	N/Q	MAI	0.36
89	116	TSH-0.58	N/Q	SAI	0.19
118	93	TSH-0.96	86%	MAI	0.76
93	126	TSH-0.56	N/Q	MAI	0.47
123	111	TSH-0.74	N/Q	SAI	0.35
56	181	TSH-0.99	N/Q	SAI	0.66

FIGURE VII-1

Circumferential Flaw Size Evaluation



10.28.93
SG2 FLAW-1

VIII. OPERATING PLAN

A. Corrective Actions

Corrective actions were based upon a conservative approach which addresses not only the observed phenomenon, but also seeks to preclude the development of the freespan cracking seen in Unit 2 and to provide mitigating actions that would minimize the impact of a tube failure. Therefore the actions presented here address circumferential cracks, freespan axial cracks, early detection of leaks and minimization of offsite dose consequences from a tube failure.

Corrective actions fall into three categories:

1. Those for mitigation of PWSCC

2. Those for mitigation of ODSCC and

3. Improvements in leak detection.

In addition to the corrective actions listed here, PVNGS will plug and stake all tubes that are identified as having circumferential cracks. Tables VIII-1 and VIII-2 provide details of the U1R4 tube plugging process.

B. Primary Water Stress Corrosion Cracking Corrective Actions

1. Temperature reduction: Unit 1 will be operated at a reduced temperature, as practical, providing mitigation of the temperature effects of PWSCC.

C. Outside Diameter Stress Corrosion Cracking Corrective Actions

1. Temperature reduction: The temperature reduction actions listed above for PWSCC also apply for ODSCC.

2. Molar ratio control: To assist in the prevention of caustic or acidic environments in crevices, molar ratio control has been implemented to promote a proper balance between cations and anions. This parameter is currently being controlled via manipulation of the condensate demineralizers.

3. Reduce iron transport: The existence of sludge on the tubesheet provides a corrosive environment for ODSCC. Iron transport to the SGs is the primary source of sludge. Iron transport will continue to be minimized by maintaining an elevated pH in the steam plant.

4. Elevated hydrazine: A corrosive environment is expected to be mitigated by operating with an elevated hydrazine concentration in the secondary system. PVNGS is currently operating with the EPRI hydrazine guideline of greater than 100 ppb. This promotes a reduced electrochemical potential, thereby reducing ODSCC.

5. Sludge lance: Sludge lancing of the tubesheet was performed and a total of 67 pounds of sludge was removed from SG 11 and 68 pounds from SG 12

6. Boric acid treatment: The unit will implement a boric acid treatment program. The purpose of boric acid treatment is to replace contaminants removed from tubesheet crevices during the sludge lance and to buffer these crevices.

D. **Primary to Secondary Leak Rate Monitoring Program**

1. SG blowdown radiation monitors: The sensitivity of the SG blowdown radiation monitors was improved by selecting the downcomer (instead of the hot leg blowdown) as the monitoring point. This sample point has greater sensitivity to leakage activity.

2. Condenser vacuum exhaust monitor: The alert setpoints for the condenser vacuum exhaust monitor was decreased to a level four times above background readings. This new setpoint provides earlier alarms for plant operators during tube leak events.

3. Procedure for determining primary to secondary tube leak rate: The preferred hierarchy of leak rate calculation methods has been revised to use noble gas grab sample from the condenser vacuum exhaust for the most accurate leak rate determination. Iodine in the SG bulk water may be utilized if the leak is so small noble gasses are not detected in the condenser vacuum exhaust grab sample. The tritium method should be used in the absence of other radionuclides.

4. Leak rate administration action plan: The leakage monitoring frequency will be increased on an increasing leak rate. 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. Modifications are currently underway to install N-16 monitors in Unit 1.

TABLE VIII-1: STEAM GENERATOR 1-1 PLUGGING LIST

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comment	Crack Extent	PLUG DESIGN	STAKE LENGTH
1	5	2	02C -0.89	22%	NDD	Cold Leg Corner Wear defect. To be plugged per PVNGS Admin limit	N/A	B&W Rolled on HL & CL	188" ATTACHED TO CL
2	4	5	03C +0.03	24%	NDD	Cold Leg Corner Wear	N/A	B&W Rolled on HL & CL	188" ATTACHED TO CL
3	2	7	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
4	1	8	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
5	2	9	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
6	1	10	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
7	49	10	TSH -1.36	MAI	NQI/NTE	Axial indications in tube not fully expanded in tubesheet (NTE)	0.51"	B&W Rolled on HL & CL	48" ATTACHED AT HL
8	54	11	TSH -0.76	MAI/52	NQI/NTE	Axial indications in tube not fully expanded in tubesheet (NTE)	0.48"	B&W Rolled on HL & CL	48" ATTACHED AT HL
9	77	16	TSH -0.30	SCI (ID)	NDD	PWSCC	0.34" or 59°	B&W Rolled on HL & CL	48" ATTACHED TO HL
10	2	17	03C -0.24	29%	<20	Cold Leg Corner Wear defect. To be plugged per PVNGS Admin limit	N/A	B&W Rolled on HL & CL	188" ATTACHED TO CL
11	62	21	TSH -0.70	MAI/59%	NTE	Axial indications in tube not fully expanded in tubesheet (NTE)	.65"	B&W Rolled on HL & CL	48" ATTACHED AT HL
12	108	49	VS2 -2.63	SVI	NDD	OD Volumetric indication which appears tc have changed slightly from last inspection	N/A	B&W Rolled on HL & CL	
13	35	60	TSH 0.00	SVI	SLG	Tubesheet volumetric indication in sludge pile NDD by bobbin		B&W Rolled on HL & CL	48" ATTACHED TO HL

TABLE VIII-1: STEAM GENERATOR 1-1 PLUGGING LIST (continued)

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comment	Crack Extent	PLUG DESIGN	STAKE LENGTH
14	81	60	VS3 +0.91	49%	29%	Vertical Strap wear	N/A	B&W Rolled on HL & CL	
15	125	64	VS5 +4.16	SVI/DEP	NDD	SVI with deposit (not a ridge deposit)	N/A	B&W Rolled on HL & CL	
16	50	75	TSH -0.15	SCI (ID)	SLG	PWSCC	0.44" or 76°	B&W Rolled on HL & CL	48" ATTACHED AT HL
17	27	78	TSH -0.65	SAI/58%	NTE	Axial indication in tube not fully expanded in tubesheet (NTE). Defect contained within tubesheet.	1.00"	B&W Rolled on HL & CL	
18	52	79	TSH -0.15	MCI (ID)	SLG	PWSCC	0.91" or 157°	B&W Rolled on HL & CL	48" ATTACHED AT HL
19	52	81	TSH -0.23	SCI (ID)	SLG	PWSCC	0.86" or 148°	B&W Rolled on HL & CL	48" ATTACHED AT HL
20	155	82	BW1 +1.93	50%	32%	Batwing Wrapper Bar Wear	N/A	B&W Rolled on HL & CL	
21	52	83	TSH -0.08	SCI (OD)	SLG	Sludge pile ODSCC	0.41" or 63°	B&W Rolled on HL & CL	48" ATTACHED AT HL
22	116	83	BWI +1.02	SVI/PDP	NDD	Several volumetric indications all with slight ridge deposit indication	N/A	B&W Rolled on HL & CL	
23	33	84	TEH +1.51	SAI/79%	NDD	ID defect found within tubsheet	1 .83"	B&W Rolled on HL & CL	
24	36	87	BW1 +1.86	27%	<20%	Stay Cylinder Batwing Wear. Per PVNGS criteria defects are plugged at > 20%	N/A	B&W Rolled on HL & CL	381" ATTACHED AT HL
25	156	87	BW1 +1.8	40%	<20 %	Batwing Wrapper Bar Wear	N/A	B&W Rolled on HL & CL	
26	149	88	08H +12.0 to 37.82 (4 seperate indications)	SVI/PDP	NDD	Several volumetric indications all with slight ridge deposit indication	N/A	B&W Rolled on HL & CL	

TABLE VIII-1: STEAM GENERATOR 1-1 PLUGGING LIST (continued)

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comment	Crack Extent	PLUG DESiGN	STAKE LENGTH
27	55	90	TSH -0.09	SCI	SLG/DTI	PWSCC 1991 distorted signal may have been precursor	0.34" or 59°	B&W Rolled on HL & CL	48" ATTACHED AT HL
28	38	91	BW1 - 1.92	24	<20%	Stay Cylinder Batwing Wear	N/A	B&W Rolled on HL & CL	387"ATTACHED AT HL
29	158	97	01C +1.50	PLI/36%	NDD	PLP with wear	N/A	B&W Rolled on HL & CL	85.5"ATTACHED AT CL
30	157	98	01C +1.53	PLP	NDD	Tube does not exhibit wear but will be removed from service per Study 02-MS-A72	N/A	B&W Rolled on HL & CL	85.5"ATTACHED AT CL
31	159	98	01C +1.64	PLI/85%	NDD	Associated with R158C97	N/A	B&W Rolled on HL & CL	85.5"ATTACHED AT CL
32	37	100	BW1 -1.82	21%	<20	Batwing Stay Cylinder Wear	N/A	B&W Rolled on HL & CL	384" ATTACHED AT HL
33	35	104	BW1 -1.96	28%	<20%	Batwing Stay Cylinder Wear	N/A	B&W Rolled on HL & CL	379" ATTACHED AT HL
34	34	105	BW1 +2.27	23%	NDD	Batwing Stay Cylinder Wear	N/A	B&W Rolled on HL & CL	376" ATTACHED AT HL
35	33	106	BW1 -2.03	25%	NDD	Batwing Stay Cylinder Wear	N/A	B&W Rolled on HL & CL	373" ATTACHED AT HL
36	35	106	BW1 -1.94	25%	NDD	Stay Cylinder Batwing Wear- No Stake is required per Staking Guideline	N/A	B&W Rolled on HL & CL	
37	158	107	04C +32	SVI/ADR	SVI based on ReReview	Considered Buff Mark Preventative Plugged based on severity of signal to prevent future detectability problems	N/A	B&W Rolled on HL & CL	
38	157	110	BW2 -1.86	41%	27%	Batwing Wrapper Bar Wear	N/A	B&W Rolled on HL & CL	

TABLE VIII-1: STEAM GENERATOR 1-1 PLUGGING LIST (continued)

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comment	Crack Extent	PLUG DESIGN	STAKE LENGTH
39	137	120	VS5 +17.12	SVI/DEP	NDD	Volumetric indication associated with a deposit. Deposit not a linear type ridge deposit		B&W Rolled on HL & CL	
40	137	130	TSH -0.13	SVI (OD)	NDD	OD Volumetric indication found at Tubesheet. May be SCC precursor		B&W Rolled on HL & CL	48" ATTACHED AT HL
41	60	131	04H +10.51	SVI	NDD	OD Volumetric indication which appears to have changed slightly from last inspection		B&W Rolled on HL & CL	
42	83	134	VS3 +1.00	42%	21%	Vertical Strap Wear	N/A	B&W Rolled on HL & CL	
43	97	138	BW1 +2.85	PDP/SVI	NDD	Volumetric indication (Buff Mark) Since indication is aasociated with PDP, tube will be preventatively plugged based on Unit 2 lessons learned	N/A	B&W Rolled on HL & CL	
44	130	149	TSC +1.38	PLI/46%	NDD	PLP with wear. PLP removed during FOSAR. Therefore no stake is required	N/A	B&W Rolled on HL & CL	
45	30	163	TSH -0.20	SAI/ETL/NBI	NDD	Small axial indication not seen with bobbin. Found by 100% TSH MRPC inspection	0.19"	B&W Rolled on HL & CL	
46	12	169	TSH -0.24	SCI (OD)	NDD	ODSCC	0.31" or 47°	B&W Rolled on HL & CL	48" ATTACHED TO HL
47	78	169	VS3 -0.80	41%	31%	Vertical Strap Wear	N/A	B&W Rolled on HL & CL	
48	50	175	07H +16.10	SVI/DEP/ 30%	20%	SVI with Deposit (not ridge deposit)	N/A	B&W Rolled on HL & CL	

TABLE VIII-1: STEAM GENERATOR 1-1 PLUGGING LIST (continued)

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comment	Crack Extent	PLUG DESIGN	STAKE LENGTH
49	77	176	TSC +0.51	PLP	NDD	Associated with PLP at R79C176	N/A	B&W Rolled on HL & CL	48" ATTACHED AT CL
50	79	176	TSC +0.51	PLI/34%	PLP	PLP with wear	N/A	B&W Rolled on HL & CL	48" ATTACHED AT CL
51	1	180	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
52	2	181	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
53	56	181	TSH -0.99	SAI (OD)	NTE	Axial indication in tube not fully expanded in tubesheet (NTE). Defect contained within tubesheet		B&W Rolled on HL & CL	
54	2	183	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
55	1	184	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
56	2	185	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL

Note 1: These tubes will be preventatively plugged and cold leg staked due to the high wear rate region (Cold Leg Corner) and the inaccessibility of the tubes without removal of the patch plates.

TABLE VIII-2: STEAM GENERATOR 1-2 PLUGGING LIST

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comments	Crack Extent	PLUG DESIGN	STAKE LENGTH
1	1	2	02C -0.71	37%	NDD	Cold Leg Corner Wear defect. To be plugged per PVNGS Admin limit	N/A	B&W Rolled on HL & CL	188" ATTACHED AT CL
2	1	4	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
3	2	5	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
4	23	6	TSH 1.15	MAI/NTE	NQI/NTE	Axial indications in tube not fully expanded in tubesheet (NTE)	0.50"	B&W Rolled on HL & CL	48" ATTACHED AT HL
5	2	7	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
6	2	9	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
7	1	10	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
8	1	16	04C +0.81	25%	NDD	Cold Leg Corner Wear defect. To be plugged per PVNGS Admin limit	N/A	B&W Rolled on HL & CL	188" ATTACHED AT CL
9	73	28	VS3 +0.57	48%	21%	Vertical Strap Wear	N/A	B&W Rolled on HL & CL	NONE
10	100	31	BW1 +2.72	PDP/SVI/59%	NDD	Freespan Volumetric Indication associated with linear deposit (PDP)	N/A	B&W Rolled on HL & CL	NONE
11	46	35	TSH +0.15	SAI/NBI	NDD	Top of tubsheet axial indication	0.17"	B&W Rolled on HL & CL	NONE
12	129	42	07H +3.65	SVI/PDP/<20	NDD	Freespan Volumetric Indication associated with linear deposit (PDP)	N/A	B&W Rolled on HL & CL	NONE

TABLE VIII-2: STEAM GENERATOR 1-2 PLUGGING LIST (continued)

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comments	Crack Extent	PLUG DESIGN	STAKE LENGTH
13	22	55	TSH +0.00	SCI(ID)	SLG	PWSCC - although indication is ID the sludge pile can affect crack growth via higher heat flux	0.55" or 95°	B&W Rolled on HL & CL	48" ATTACHED AT HL
14	23	56	TSH +0.11	SCI(ID)	SLG	PWSCC	1.32" or 227°	B&W Rolled on HL & CL	48" ATTACHED AT HL
15	23	60	TSH -0.02	SCI(ID)	SLG	PWSCC	0.99" or 170°	B&W Rolled on HL & CL	48" ATTACHED AT HL
16	25	60	TSH -0.01	SCI(ID)	SLG	PWSCC	1.22" or 210°	B&W Rolled on HL & CL	48" ATTACHED AT HL
17	29	60	TSH +0.19	SVI(OD)	SLG	OD Volumetric indication at the Tubesheet - associated with sludge pile	N/A	B&W Rolled on HL & CL	48" ATTACHED AT HL
18	35	60	TSH -0.04	SCI(ID)	SLG	PWSCC	1.06" or 182°	B&W Rolled on HL & CL	48" ATTACHED AT HL
19	39	60	TSH +0.00	SCI(ID)	SLG	PWSCC	0.90" or 155°	B&W Rolled on HL & CL	48" ATTACHED AT HL
20	137	60	TSH -0.29	SCI(OD)	NDD	Sludge pile ODSCC	0.68" or 104°	B&W Rolled on HL & CL	48" ATTACHED AT HL
21	32	61	TSH -0.06	SCI(ID)	SLG	PWSCC	0.40" or 69°	B&W Rolled on HL & CL	48" ATTACHED AT HL
22	34	61	TSH -0.03	SCI(ID)	SLG	PWSCC	0.38" or 65°	B&W Rolled on HL & CL	48" ATTACHED AT HL
23	36	61	TSH +0.09	SCI(OD)	SLG	Sludge pile ODSCC	0.75" or 115°	B&W Rolled on HL & CL	48" ATTACHED AT HL
24	44	61	TSH +0.00	SCI(ID)	SLG	PWSCC	0.32" or 55°	B&W Rolled on HL & CL	48" ATTACHED AT HL
25	1	62	TSH +0.01	SVI(OD)	NDD	OD Volumetric Indication at Tubesheet	N/A	B&W Rolled on HL & CL	48" ATTACHED AT HL
26	35	62	TSH +0.16	SCI(OD)	SLG	Sludge pile ODSCC	0.21" or 32°	B&W Rolled on HL & CL	48" ATTACHED AT HL
27	43	62	TSH +0.11	SCI(OD)	SLG	Sludge pile ODSCC	0.27" or 41°	B&W Rolled on HL & CL	48" ATTACHED AT HL
28	47	62	TSH -0.01	SCI(ID)	SLG	PWSCC	1.15" or 198°	B&W Rolled on HL & CL	48" ATTACHED AT HL
29	30	63	TSH -0.03	SCI(ID)	SLG	PWSCC	0.48" or 83°	B&W Rolled on HL & CL	48" ATTACHED AT HL
30	29	64	TSH - 0.10	SCI(OD)	SLG	Sludge pile ODSCC	0.31" or 47°	B&W Rolled on HL & CL	48" ATTACHED AT HL

TABLE VIII-2: STEAM GENERATOR 1-2 PLUGGING LIST (continued)

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comments	Crack Extent	PLUG DESIGN	STAKE LENGTH
31	37	64	TSH +0.31	SVI(OD)	SLG	OD Volumetric indication at the Tubesheet - associated with sludge pile	N/A	B&W Rolled on HL & CL	48" ATTACHED AT HL
32	53	64	TSH -0.02	SCI(ID)	SLG	PWSCC	0.60" or 103°	B&W Rolled on HL & CL	48" ATTACHED AT HL
33	28	65	TSH +0.00	SCI(ID)	SLG	PWSCC	0.29" or 50°	B&W Rolled on HL & CL	48" ATTACHED AT HL
34	35	66	TSH +0.13	SVI(OD)	SLG	OD Volumetric indication at the Tubesheet - associated with sludge pile	N/A	B&W Rolled on HL & CL	48" ATTACHED AT HL
35	37	66	TSH +0.27	SVI(OD)	SLG	OD Volumetric indication at the Tubesheet - associated with sludge pile	N/A	B&W Rolled on HL & CL	48" ATTACHED AT HL
36	51	66	TSH +0.12	SCI(OD)	SLG	Sludge pile ODSCC	0.24" or 37°	B&W Rolled on HL & CL	48" ATTACHED AT HL
37	34	67	TSH +0.06 TSH +0.11	SCI(ID) SCI(OD)	SLG	PWSCC Sludge pile ODSCC	0.18" or 31° 0.28" or 43°	B&W Rolled on HL & CL	48" ATTACHED AT HL
38	36	67	TSH +0.14	SVI(OD)	SLG	OD Volumetric indication at the Tubesheet - associated with sludge pile	N/A	B&W Rolled on HL & CL	48" ATTACHED AT HL
39	38	67	TSH +0.13	SCI(OD)	SLG	Sludge pile ODSCC	0.23" or 35°	B&W Rolled on HL & CL	48" ATTACHED AT HL
40	40	67	TSH +0.06	SCI(OD)	SLG/DTI	Sludge Pile ODSCC	0.24" or 37°	B&W Rolled on HL & CL	48" ATTACHED AT HL
41	39	68	TSH +0.09	SCI(OD)	SLG	Sludge Pile ODSCC	0.21" or 32°	B&W Rolled on HL & CL	48" ATTACHED AT HL
42	43	68	TSH +0.02 TSH +0.22	SCI(ID) SCI(OD)	SLG	PWSCC Sludge Pile ODSCC	0.45" or 77° 0.27" or 41°	B&W Rolled on HL & CL	48" ATTACHED AT HL
43	51	68	TSH +0.18	SCI(OD)	SLG	Sludge Pile ODSCC	0.13" or 20°	B&W Rolled on HL & CL	48" ATTACHED AT HL

TABLE VIII-2: STEAM GENERATOR 1-2 PLUGGING LIST (continued)

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comments	Crack Extent	PLUG DESIGN	STAKE LENGTH
44	42	69	TSH +0.24	SVI(OD)	SLG	OD Volumetric indication at the Tubesheet - associated with sludge pile	N/A	B&W Rolled on HL & CL	48" ATTACHED AT HL
45	46	69	TSH +0.39	SVI(OD)	SLG	OD Volumetric indication at the Tubesheet - associated with sludge pile	N/A	B&W Rolled on HL & CL	48" ATTACHED AT HL
46	45	70	TSH +0.11	SCI(OD)	SLG	Sludge Pile ODSCC	0.42" or 64°	B&W Rolled on HL & CL	48" ATTACHED AT HL
47	42	71	TSH +0.13	SCI(OD)	SLG	Sludge Pile ODSCC	0.26" or 40°	B&W Rolled on HL & CL	48" ATTACHED AT HL
48	44	71	TSH +0.07	SCI(OD)	SLG	Sludge Pile ODSCC	0.22" or 34°	B&W Rolled on HL & CL	48" ATTACHED AT HL
49	52	71	TSH +0.28	SCI(OD)	SLG	Sludge Pile ODSCC	0.45" or 69°	B&W Rolled on HL & CL	48" ATTACHED AT HL
50	54	71	TSH -0.04	SCI(ID)	SLG	PWSCC	1.67" or 287°	B&W Rolled on HL & CL	48" ATTACHED AT HL
51	56	71	TSH -0.12 TSH +0.34	SCI(ID) SCI(OD)	SLG	PWSCC Sludge Pile ODSCC	0.34" or 57° 0.45" or 69°	B&W Rolled on HL & CL	48" ATTACHED AT HL
52	57	72	TSH +0.23	SCI(OD)	SLG	Sludge Pile ODSCC	0.33" or 50°	B&W Rolled on HL & CL	48" ATTACHED AT HL
53	87	72	TSH -0.83	MAI (86%)/ NTE	NTE	Axial indications in tube not fully expanded in tubesheet (NTE)	0.53"	B&W Rolled on HL & CL	48" ATTACHED AT HL
54	54	73	TSH -0.02	SCI(ID)	SLG	PWSCC	0.51" or 88°	B&W Rolled on HL & CL	48" ATTACHED AT HL
55	60	73	TSH -0.08	SCI(ID)	SLG	PWSCC	0.28" or 48°	B&W Rolled on HL & CL	48" ATTACHED AT HL
56	43	74	TSH +0.18	SCI(OD)	SLG	Sludge Pile ODSCC	0.43" or 66°	B&W Rolled on HL & CL	48" ATTACHED AT HL
57	59	74	TSH +0.21	SCI(OD)	SLG	Sludge Pile ODSCC	0.15" or 23°	B&W Rolled on HL & CL	48" ATTACHED AT HL
58	61	74	TSH +0.16	SCI(OD)	SLG	Sludge Pile ODSCC	0.21" or 32°	B&W Rolled on HL & CL	48" ATTACHED AT HL
59	87	74	TSH -0.67	MAI/NTE	NTE	Axial indications in tube not fully expanded in tubesheet (NTE)	0.28"	B&W Rolled on HL & CL	48" ATTACHED AT HL
60	42	75	TSH +0.05	SCI(OD)	SLG	Sludge Pile ODSCC	0.35" or 53°	B&W Rolled on HL & CL	48" ATTACHED AT HL

TABLE VIII-2: STEAM GENERATOR 1-2 PLUGGING LIST (continued)

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comments	Crack Extent	PLUG DESIGN	STAKE LENGTH
61	46	75	TSH +0.14	SCI(OD)	SLC	Sludge Pile ODSCC	0.25" or 38°	B&W Rolled on HL & CL	48" ATTACHED AT HL
62	48	75	TSH -0.04 TSH +0.75	SCI(ID) SVI(OD)	SLG	PWSCC OD Volumetric Indication at Tubesheet	0.16" or 28°	B&W Rolled on HL & CL	48" ATTACHED AT HL
63	54	75	TSH +0.00 TSH +0.23	MCI(ID) SCI(OD)	SLG	PWSCC Sludge Pile ODSCC	2.01" or 346° 0.28" or 43°	B&W Rolled on HL & CL	48" ATTACHED AT HL
64	56	75	TSH +0.21	SCI(OD)	SLG	Sludge Pile ODSCC	0.55" or 84°	B&W Rolled on HL & CL	48" ATTACHED AT HL
65	58	75	TSH +0.19	SCI(OD)	SLG	Sludge Pile ODSCC	0.67" or 102°	B&W Rolled on HL & CL	48" ATTACHED AT HL
66	62	75	TSH +0.26	SCI(OD)	SLG	Sludge Pile ODSCC	0.94" or 144°	B&W Rolled on HL & CL	48" ATTACHED AT HL
67	64	75	TSH +0.23	SCI(OD)	SLG	Sludge Pile ODSCC	0.30" or 46°	B&W Rolled on HL & CL	48" ATTACHED AT HL
68	49	76	TSH -0.02 TSH +0.22	SCI(ID) SVI(OD)	SLG	PWSCC OD Volumetric Indication at Tubesheet	0.50" or 86°	B&W Rolled on HL & CL	48" ATTACHED AT HL
69	51	76	TSH +0.11	SVI(OD)	SLG	OD Volumetric indication at the Tubesheet associated with sludge pile	N/A	B&W Rolled on HL & CL	48" ATTACHED AT HL
70	53	76	TSH -0.02 TSH +0.11	SCI(ID) SCI(OD)	SLG	PWSCC Sludge Pile ODSCC	0.32" or 55° 0.18" or 28°	B&W Rolled on HL & CL	48" ATTACHED AT HL
71	55	76	TSH +0.01	SCI(ID)	SLG	PWSCC	0.79" or 136°	B&W Rolled on HL & CL	48" ATTACHED AT HL
72	59	76	TSH +0.16	MCI(OD)	SLG	Sludge Pile ODSCC	0.55 or 84°	B&W Rolled on HL & CL	48" ATTACHED AT HL
73	61	76	TSH +0.14	SCI(OD)	SLG	Sludge Pile ODSCC	0.45" or 69°	B&W Rolled on HL & CL	48" ATTACHED AT HL
74	36	77	TSH +0.21	SCI(OD)	SLG	Sludge Pile ODSCC	0.25" or 38°	B&W Rolled on HL & CL	48" ATTACHED AT HL
75	48	77	TSH +0.10	SCI(OD)	SLG	Sludge Pile ODSCC	0.61" or 93°	B&W Rolled on HL & CL	48" ATTACHED AT HL
76	58	77	TSH +0.00	SCI(ID)	SLG	PWSCC	0.58" or 100°	B&W Rolled on HL & CL	48" ATTACHED AT HL
77	60	77	TSH -0.07 TSH +0.26	SCI(ID) SCI(OD)	SLG	PWSCC Sludge Pile ODSCC	0.88" or 151° 0.57" or 87°	B&W Rolled on HL & CL	48" ATTACHED AT HL

TABLE VIII-2: STEAM GENERATOR 1-2 PLUGGING LIST (continued)

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comments	Crack Extent	PLUG DESIGN	STAKE LENGTH
78	49	78	TSH +0.04 TSH +0.18	SCI(ID) SCI(OD)	SLG	PWSCC Sludge Pile ODSCC	0.76" or 131° 0.35" or 53°	B&W Rolled on HL & CL	48" ATTACHED AT HL
79	51	78	TSH -0.02 TSH +0.29	SCI(ID) SVI(OD)	SLG	PWSCC OD Volumetric Indication at Tubesheet	0.41" or 71°	B&W Rolled on HL & CL	48" ATTACHED AT HL
80	53	78	TSH -0.03	SCI(ID)	SLG	PWSCC	0.87" or 150°	B&W Rolled on HL & CL	48" ATTACHED AT HL
81	63	78	TSH +0.05	SCI(OD)	SLG	Sludge Pile ODSCC	0.38" or 58°	B&W Rolled on HL & CL	48" ATTACHED AT HL
82	65	78	TSH +0.15	SCI(OD)	SLG	Sludge Pile ODSCC	0.48" or 73°	B&W Rolled on HL & CL	48" ATTACHED AT HL
83	69	78	TSH -0.02	SCI(ID)	SLG	PWSCC	0.30" or 52°	B&W Rolled on HL & CL	48" ATTACHED AT HL
84	38	79	TSH +0.18	SVI(OD)	SLG	OD Volumetric Indication at Tubesheet	N/A	B&W Rolled on HL & CL	48" ATTACHED AT HL
85	48	79	TSH +0.02	SCI(ID)	SLG/DTI	PWSCC	1.33" or 229°	B&W Rolled on HL & CL	48" ATTACHED AT HL
86	54	79	TSH -0.05	SCI(ID)	SLG	PWSCC	0.33" or 57°	B&W Rolled on HL & CL	48" ATTACHED AT HL
87	60	79	TSH +0.21	SCI(OD)	SLG	Sludge Pile ODSCC	0.21" or 32°	B&W Rolled on HL & CL	48" ATTACHED AT HL
88	57	80	TSH +0.28	SCI(OD)	SLG	Sludge Pile ODSCC	0.35" or 53°	B&W Rolled on HL & CL	48" ATTACHED AT HL
89	52	81	TSH +0.12	SVI(OD)	SLG	OD Volumetric indication at the Tubesheet associated with sludge pile	N/A	B&W Rolled on HL & CL	48" ATTACHED AT HL
90	54	81	TSH +0.12	SCI(ID)	SLG	PWSCC	0.44" or 76°	B&W Rolled on HL & CL	48" ATTACHED AT HL
91	58	81	TSH +0.13	SVI(OD)	NDD	OD Volumetric Indication at Tubesheet	N/A	B&W Rolled on HL & CL	48" ATTACHED AT HL
92	53	82	TSH +0.14 TSH +0.15	SVI(OD) SCI(OD)	 SLG	OD Volumetric Indication at Tubesheet Sludge pile ODSCC	N/A 0.49" or 75°	B&W Rolled on HL & CL	48" ATTACHED AT HL
93	67	82	TSH +0.14	SCI(OD)	SLG	Sludge pile ODSCC	0.71" or 108°	B&W Rolled on HL & CL	48" ATTACHED AT HL
94	48	83	TSH +0.01	SCI(ID)	SLG	PWSCC	0.27" or 46°	B&W Rolled on HL & CL	48" ATTACHED AT HL

TABLE VIII-2: STEAM GENERATOR 1-2 PLUGGING LIST (continued)

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comments	Crack Extent	PLUG DESIGN	STAKE LENGTH
95	47	84	TSH +0.00	SCI(ID)	SLG	PWSCC	0.28" or 48°	B&W Rolled on HL & CL	48" ATTACHED AT HL
96	65	84	TSH +0.13 TSH +0.13 TSH +0.13	SCI(OD) SCI(OD) SCI(OD)	SLG	Sludge pile ODSCC	0.43" or 66° 0.36" or 55° 0.22" or 34°	B&W Rolled on HL & CL	48" ATTACHED AT HL
97	64	85	TSH +0.18	SCI(OD)/DTI	SLG	Sludge pile ODSCC	0.79" or 121°	B&W Rolled on HL & CL	48" ATTACHED AT HL
98	90	85	VS3 +22.53	SVI/BLI/NQI	NQI	Preventative plug. Large BLI may mask future defects.	N/A	B&W Rolled on HL & CL	NONE
99	47	86	TSH +0.03	SCI(ID)	SLG	PWSCC	0.50" or 86°	B&W Rolled on HL & CL	48" ATTACHED AT HL
100	69	86	TSH -0.01	SCI(ID)	SLG	PWSCC	0.60" or 103°	B&W Rolled on HL & CL	48" ATTACHED AT HL
101	54	87	TSH -0.01	SCI(ID)	SLG	PWSCC	0.58" or 100°	B&W Rolled on HL & CL	48" ATTACHED AT HL
102	64	87	TSH +0.13	SCI(OD)	SLG	Sludge pile ODSCC	0.42" or 64°	B&W Rolled on HL & CL	48" ATTACHED AT HL
103	64	89	TSH -0.07	SCI(ID)	SLG	PWSCC	0.24" or 41°	B&W Rolled on HL & CL	48" ATTACHED AT HL
104	38	91	01H -0.19	SVI(OD)	NDD	OD Volumetric Indication at FDP.	N/A	B&W Rolled on HL & CL	387" ATTACHED AT HL
105	40	91	TEH +3.74	88%	OBS	Deep ID Gouge	N/A	B&W Rolled on HL & CL	392" ATTACHED AT HL
106	39	94	BW1 -2.20	21%	<20%	Stay Cyl. Bat Wing Wear	N/A	B&W Rolled on HL & CL	390" ATTACHED AT HL
107	122	101	BW1 +0.58	SVI(42%)	NDD	Arc SVI associated with PDP & BOW	N/A	B&W Rolled on HL & CL	NONE
108	159	102	BW2 +1.97	40%	20%	Bat Wing wrapper bar Wear	N/A	B&W Rolled on HL & CL	NONE
109	158	103	BW2 +1.93	43%	26%	Bat Wing wrapper bar Wear	N/A	B&W Rolled on HL & CL	NONE
110	34	105	BW1 -1.78	22%	NDD	Stay Cyl Bat Wing Wear	N/A	B&W Rolled on HL & CL	376" ATTACHED AT HL
111	158	107	VS7 +0.74	44%	<20%	Vertical Strap Wear	N/A	B&W Rolled on HL & CL	NONE

TABLE VIII-2: STEAM GENERATOR 1-2 PLUGGING LIST (continued)

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comments	Crack Extent	PLUG DESIGN	STAKE LENGTH
112	28	111	TSH -0.50	SAI/NTE	NTE	Axial indication in tube not fully expanded in tubesheet (NTE)	.25"	B&W Rolled on HL & CL	360" ATTACHED AT HL (Preventatively Staked for Stay Cyl Bat Wing Wear)
113	93	112	TSH -0.56	MAI/NTE	NTE	Axial indications in tube not fully expanded in tubesheet (NTE)	.36"	B&W Rolled on HL & CL	48" ATTACHED AT HL
114	148	115	BW1 +1.72	SVI/NQI/PDP	NDD	Single Volumetric Indication associated with PDP and BOW	0.5"	B&W Rolled on HL & CL	NONE
115	89	116	TSH -0.58	SAI/NTE/ NQI	NTE	Axial indication in tube not fully expanded in tubesheet (NTE)	.19"	B&W Rolled on HL & CL	NONE
116	22	117	01H -0.08	SVI(OD)/DSI	NDD	OD Volumetric Indication at FDP.	N/A	B&W Rolled on HL & CL	NONE
117	60	119	BW1 +15.25	SVI	NDD	Arc SVI	N/A	B&W Rolled on HL & CL	NONE
118	93	120	TSH -0.96	MAI/NTE (86%)	NTE	Axial indications in tube not fully expanded in tubesheet (NTE)	.76"	B&W Rolled on HL & CL	48" ATTACHED AT HL
119	110	121	BW1 +1.18	SVI(51%) PDP/BOW	NDD	Arc Single Volumetric Indication associated with PDP and BOW	N/A	B&W Rolled on HL & CL	NONE
120	93	126	TSH -0.56	MAI/NTE/ NQI	NTE	Axial indications in tube not fully expanded in tubesheet (NTE)	.47"	B&W Rolled on HL & CL	48" ATTACHED AT HL
121	101	132	BW1 +2.73	36%	NDD	Arc SVI	N/A	B&W Rolled on HL & CL	NONE
122	73	160	VS5 +1.05	45%	24%	Vertical Strap Wear	N/A	B&W Rolled on HL & CL	NONE
123	111	160	TSH -0.74	SAI/NTE/ NQI	NTE	Axial indication in tube not fully expanded in tubesheet (NTE)	.35"	B&W Rolled on HL & CL	NONE
124	1	174	02C -0.97	21%	NDD	Cold Leg Corner Wear	N/A	B&W Rolled on HL & CL	188" ATTACHED AT CL

TABLE VIII-2: STEAM GENERATOR 1-2 PLUGGING LIST (continued)

#	Row	Column	Elevation	ECT93(%)	ECT92(%)	Comments	Crack Extent	PLUG DESIGN	STAKE LENGTH
125	1	176	03C -1.03	20%	NDD	Cold Leg Corner Wear	N/A	B&W Rolled on HL & CL	188" ATTACHED AT CL
126	1	180	03C -0.17	22%	NDD	Cold Leg Corner Wear	N/A	B&W Rolled on HL & CL	188" ATTACHED AT CL
127	2	181	NA	NA	NA	Preventatively Plug[1]	NA	B&W Rolled on HL & CL	188" ATTACHED TO CL
128	7	184	03C +1.00	20%	NDD	Cold Leg Corner Wear	N/A	B&W Rolled on HL & CL	188" ATTACHED AT CL
129	26	185	TSC +0.27	SVI	NDD	OD Volumetric Indication at Tubesheet	N/A	B&W Rolled on HL & CL	188" ATTACHED AT CL
130	3	186	03C +0.06	22%	NDD	Cold Leg Corner Wear	N/A	B&W Rolled on HL & CL	188" ATTACHED AT CL
131	3	188	02C +0.11	31%	NDD	Cold Leg Corner Wear	N/A	B&W Rolled on HL & CL	188" ATTACHED AT CL

Note 1: These tubes will be preventatively plugged and cold leg staked due to the high wear rate region (Cold Leg Corner) and the inaccessibility of the tubes without removal of the patch plates.

IX. OPERATING INTERVAL / BASIS FOR RESTART

APS has determined that PVNGS Unit 1 is safe to operate for a complete fuel cycle. This conclusion is based on the results of a comprehensive ECT inspection program which included a 100% bobbin inspection and extensive inspection by MRPC probe including 100% of the hot leg tubesheet transition area in both SGs as well as over 2300 tubes in each steam generator from the 08H support to the vertical strap. The scope of this inspection ensures that conditions such as the circumferential cracking problem were discovered.

There were no free span upper bundle axial crack indications observed in this ECT program, and all "I" code indications were resolved or plugged. A total of four SVIs were located in the "MRPC" arc region and may be indicative of early intergranular attack, and UT inspection of an accessible SVI did not indicate a crack. This supports the conclusion that accelerated upper bundle IGSCC, such as that observed in Unit 2, is not present in Unit 1, and confirms that differences in chemistry controls between the units can affect the initiation and growth of IGSCC.

Circumferential cracks observed in each steam generator were sized for length using MRPC and UT methods, and UT methods were used to estimate depth. The most conservative (longest) crack value of length was used and a through wall crack was assumed to identify which cracks would be used in the RG 1.121 analysis. Five tubes were tested with in situ pressure test methods to verify compliance; all passed the test. This provided assurance that the corrosion mechanisms (PWSCC and ODSCC) did not produce cracks in excess of the R.G. 1.121 limits since the last inspection in the third refueling outage.

Corrective actions have been taken or are planned to be implemented to address the environment producing PWSCC. As a conservative measure preventive actions have been taken or are planned to be implemented to prevent the accelerated IGSCC observed in the Unit 2 free span areas. Therefore, these corrosion mechanisms are not expected to be a factor significantly degrading tube integrity during Cycle 5.

Following the tube rupture event in Unit 2 a number of actions were implemented to minimize offsite doses in the unlikely event of a multiple tube rupture with a MSLB. These include administrative limits on primary to secondary leak rate and a maximum permitted Dose Equivalent Iodine concentration, revised leak rate determination methods, improved diagnostic methods, and enhanced radiation monitoring. These actions are described in References 13 and 14, and have been implemented in all three PVNGS Units. A safety analysis was performed in support of the Unit 2 restart as described in References 13 and 14. This safety analysis was generic to the three PVNGS Units and predicts that in the event of a multiple tube rupture MSLB accident, with the mitigating actions described above, the offsite dose consequences are less than 10CFR100 limits.

This multi-tier approach:

- Identifies by inspection any accelerated corrosion mechanisms that are present, allowing APS to identify the proper corrective actions
- Implements actions conservatively to address not only observed corrosion mechanisms but preclude the accelerated mechanism observed in Unit 2

- Specifies monitoring and mitigating actions in case a tube rupture should occur
- Analyzes the impact of a tube rupture to confirm that the consequences do not exceed 10CFR100 limits.

It is by this defense in depth approach that APS concludes operation of Unit 1 for a full fuel cycle would not constitute a safety concern.

X. REFERENCES

1. "Unit 2 Steam Generator Tube Rupture Analysis Report", submitted to the NRC staff as enclosure 2 to William Conway's letter 102-02569-WFC/JRP, dated July 18, 1993

2. EPRI TR-102134, PWR Secondary Water Chemistry Guidelines", Revision 3, May, 1993.

3. "Secondary System Iron Transport Study", PVNGS, Unit 2, August, 1991.

4. APS Memorandum 237-01165-JNH, "Unit 1 Shutdown Hideout Return Data - September 5, 1993", October 27, 1993.

5. APS Memorandum 237-01164-JNH, "Unit 3 Downpower Hideout Return Data - September 25, 1993", October 25, 1993.

6. AES 92071723-1-1, "Predictive Modeling of Steam Generator Tubing Degradation for Palo Verde Nuclear Generating Station, Units 1, 2, and 3", Aptech Engineering Services, Inc., April, 1993.

7. EPRI NP-5558-SL, "Boric Acid Application Guidelines for Intergranual Corrosion Inhibition", Revision 1, December, 1990.

8. "Evaluation of Steam Generator Wet Layup Out-of-Specification Condition for Palo Verde Units 1 and 3, Arizona Public Service, EERs 89-RC295 and 89-RC296", ABB-Combustion Engineering Nuclear Power, June, 1990.

9. ASM Metals Handbook, 9th Edition, Volume 13, Pages 941-944.

10 CENPD-28, "Combustion Engineering Nuclear Steam Supply System Chemistry Manual", Revision 3, September 1982.

11. PVNGS Engineering Report, "Condenser Tube Leak Assessment, August 1992.

12. Letter dated June 25, 1993, from C.M. Trammell, Senior Project Manager, Project Directorate V, Office of NRR, USNRC, to W.F. Conway, Executive VP, Nuclear, APS, "Steam Generator Tube Evaluation".

13. Letter 102-02585, dated July 25, 1993, from W.F. Conway, Executive VP, Nuclear, APS, to NRC, "Steam Generator Tube Evaluation".

14. Letter 102-02593, dated July 30, 1993, from W.F. Conway, Executive VP, Nuclear, APS, to NRC, "Steam Generator Tube Rupture Analysis".

15. EPRI NP-6626-SD, "Belgian Approach to Steam Generator Tube Plugging for Primary Water Stress Corrosion Cracking", March 1990.

16. USNRC Regulatory Guide 1.121, "Basis for Plugging Degraded PWR Steam Generator Tubes", For Comment, August 1976.

17. EPRI NP-7198-S, "Proceedings: 1990 EPRI Workshop on Circumferential Cracking of Steam Generator Tubes", March 1991.

18. EPRI TR-101103, "Proceedings:1991 EPRI Workshop on Secondary Side Intergranular Corrosion Mechanisms", August 1992.

19. Minutes, CEOG Materials and Chemistry Subcommittee, April 29-30, 1993.

20. V-CE-35658, "CE Assessment of Palo Verde, Unit 2 Steam Generator Tubes ECT Inspection Results Obtained in April 1988", April 21, 1988.

XII. APPENDICES

A. Industry Review

A review of Industry Events on INPO's Nuclear Network was performed to identify other Nuclear Utilities with circumferential cracking in the tubesheet expansion transition region. Among the Combustion Engineering units to identify this phenomenon are Arkansas Nuclear One Unit 2 (ANO 2), Maine Yankee, Millstone 2, San Onofre 2, and St. Lucie 1. These units were contacted by PVNGS to discuss the cause of their circumferential cracking, and the corrective actions initiated to reduce the potential for the reoccurrence of this cracking and to extend steam generator life.

1. Arkansas Nuclear One 2

ANO 2 has experienced OD-initiated circumferential cracking at the hot leg "explansion" (explosive expansion) transition region. These cracks are primarily located in the "kidney bean" area and are believed to be temperature-related. A review of chemistry data failed to identify any singular event that could account for these defects. Sulfates and lead have been identified in sludge samples from the steam generators. ANO believes that early poor chemistry control led to acid sulfate attack of the Alloy 600 tubing, causing IGSCC. The susceptibility of Alloy 600 to stress corrosion cracking, high residual stress in the transition region of the tube, the buildup of sludge containing a known activating agent at the transition region, and high hot leg temperatures have been determined to be the contributing factors to this cracking. Corrective actions taken to mitigate this cracking include boric acid treatment, the use of morpholine to increase secondary pH, sludge lancing, and the reduction of hot leg temperature from 607°F to 599°F.

2. Maine Yankee

Maine Yankee has experienced ID-initiated circumferential cracking at the hot leg explansion transition region. This cracking has been characterized as PWSCC. The buildup of sludge, high hot leg temperatures, high residual stress at the transition region, and the susceptibility of Alloy 600 tubing are believed to be the contributing factors to the cracking. The sludge buildup is believed to act as an insulator, increasing the temperature of the affected tubes. Corrective actions include sludge lancing, reduction of the hot leg temperature from 602°F to 599°F, removal of copper-bearing feedwater heaters, and the use of morpholine to increase secondary pH in an effort to reduce sludge buildup.

3. **Millstone 2**

Millstone 2 experienced OD-initiated circumferential cracking at both the hot leg and cold leg explansion transition region. A root cause of the cracking was not identified; however, it was believed to have been a caustic crevice attack. The high hot leg temperatures, high residual stress at the transition region, and the susceptibility of Alloy 600 tubing to SCC were identified as contributing factors. Boric acid treatment was successfully used to increase the lifespan of the generators until they could be replaced. Millstone 2 is now operating with new steam generators using Alloy 690 tubing.

4. **San Onofre 2**

San Onofre 2 has identified circumferential cracking at the hot leg explansion transition region. At this time it has not been determined whether it was OD or ID-initiated or what the root cause of this problem was. A corrective action plan was not discussed with San Onofre.

5. **St. Lucie 1**

St. Lucie 1 has experienced OD-initiated circumferential cracking at the hot leg explansion transition region. Sulfates and lead have been identified in sludge samples from the steam generators. Improper operation of the feedwater demineralizers is believed to have caused acid sulfate attack of the Alloy 600 tubing resulting in IGSCC. Transgranular cracking has also been identified and attributed to the presence of lead. St. Lucie also determined the high hot leg temperatures, high residual stress at the transition region, and the susceptibility of Alloy 600 tubing to SCC as contributing factors to the cracking. St. Lucie has reduced hot leg temperature from 604°F to 597°F, and instituted chemistry changes in an effort to increase the lifespan of the steam generators.

6. **Summary**

Industry reports show that circumferential cracking has been observed at the tube expansion transition region of steam generators at numerous CE and Westinghouse plants. Causal factors include the susceptibility of Alloy 600 to stress corrosion cracking, high residual stress in the tube transition expansion region of steam generators, inadequate control of secondary chemistry, the buildup of sludge at the transition expansion region, and high hot leg temperatures. Corrective actions taken to mitigate this cracking include boric acid treatment, the use of morpholine or ETA to increase secondary pH and reduce iron transport, sludge lancing of tubesheets to remove sludge deposits, molar ratio control, and the reduction of hot leg temperature. Additional corrective actions being evaluated in the industry include shot peening of the expansion transition region to relieve stress, and nickel plating the ID of the tubes to protect them from PWSCC.

B. **Steam Generator Description**

1. **Design Data and Performance Parameters**

Each Palo Verde Unit utilizes two SGs which are vertical tube and shell heat exchangers approximately 68 feet in height with a steam drum diameter of 20 feet. The Palo Verde steam generators were designed and fabricated by Combustion Engineering, and are currently the only operating units of this design (System80). The steam generator arrangement is shown in Figure XII-1.

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 the moisture content of the steam to 0.25% wt during normal operation at full power.

The primary side (high pressure) of the steam generator consists of the hemispherical lower head, the tubesheet and the tubes. A divider plate with tongue and groove construction separates the head into inlet and outlet chambers. A 42-inch nozzle provides entrance of reactor coolant into the steam generator which passes through the heat transfer tubes and exits through two 30-inch outlet nozzles. The unit is supported by a skirt attached to the bottom head. The secondary side of the steam generator consists of two cylindrical shells, joined by a conical section to the steam drum.

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 stay cylinder is a hollow, cylindrical tube located in the center of the steam generator. The stay cylinder supports the primary plenum plate, the divider plate separating the economizer and evaporator regions on the steam generator secondary side, and provides rigidity to the tube sheet to minimize tubesheet bowing. A summary of pertinent design and operating data is provided below:

STEAM GENERATOR DATA

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

Primary Side

Design Pressure	2500 psia
Design Temperature	650°F
Design Thermal Power	3817 MWt
Coolant Flow in Each Loop	82×10^6 lbm/hr
Normal Operating Pressure	2250 psia
Normal Operating SG Inlet Temp	621.2°F
Normal Operating SG Outlet Temp	564.5°F
Coolant Volume	2317 ft^3

Secondary Side

Design Pressure	1270 psia
Design Temperature	575°F
Normal Operating Saturated Steam Pressure at 100% power	1070 psia
Normal Operating Steam Temp at 100% Steam Flow per SG	553°F
100% Steam Flow per SG	8.59×10^6 lbm/hr
Maximum Blowdown Flow	738,740 lbm/hr

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 (OD)	0.75 inch

2. Steam Generator Materials

The steam generator's pressure containing members are constructed of low alloy steel (P3). The tubesheet is a 23.5 inches thick low alloy steel base, with ¼ inch thick Alloy 600 cladding on the primary surfaces. The tubes are made of high temperature mill annealed Alloy 600 (SB-163). All tube supports were constructed primarily from 409 ferritic stainless steel. The flow distribution plates are made from 405 ferritic stainless steel material. The structural tiedown sections of the supports, such as the partial eggcrate scallop bars and eggcrate and batwing wrapper bars, were constructed from carbon steel. To minimize tube denting, no carbon steels are in direct contact with the steam generator tubing except for the tubesheet and the scallop bars on the partial eggcrates.

3. **Tube Design**

Each steam generator contains 11,012 tubes which are ¾ inch OD, and have a nominal wall thickness of 0.042 inches and an average heated length of 57.75 feet. Tubes were expanded into the tubesheet by a method known as explansion (explosive/expansion) for the entire tubesheet thickness. 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 XII-2. The shorter tubes, which have 180° bends, are at the center of the tube bundle in the first 18 rows. All subsequent rows have double 90° bends. The vacant space (4¼ 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 on the secondary side of the steam generator.

4. **Internal Support Structures**

The steam generator tube supports were designed to provide tube bundle stability during normal plant operation or combined seismic/accident conditions while offering minimum restrictions to steam/water flow in the tube bundle to prevent formation of crud and deposit buildup.

The steam generators were designed to ensure that critical vibration frequencies would not occur during either normal operation or abnormal conditions. The tube bundle/support configuration was designed and fabricated with consideration given to secondary side flow induced vibrations. In addition, the steam generator support 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 XII-3 for the location and designation of the tube supports.

Flow Distribution Plate (01H and 01C)

The flow distribution plate is a 405 ferritic stainless steel plate with drilled flow holes. Different hole sizing forces downcomer/feedwater to flow radially across the tubesheet to permit fluid to pass evenly upward around the tubes in axial flow region. Although not considered a true support, the hot and cold side flow distribution plates are designated 01H and 01C respectively for eddy current testing purposes.

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

Horizontal eggcrate supports are a diagonal eggcrate design. The eggcrate design allows for the maximum flow area while providing sufficient horizontal stabilization for the tubes to protect the bundle from mechanical or flow induced vibration. The eggcrate supports are designated 02H through 09H and 02C through 09C for tracking purposes. The top two horizontal eggcrate supports are partial eggcrates and only support a portion of the tubes. The partial eggcrates are stiffened by a carbon steel scallop bar welded onto the face of the eggcrate.

Batwings

Batwing stabilizers horizontally support the bends in the U-tubes (see Figure XII-4). The purpose of the batwing stabilizers was to prevent tube-to-tube contact between columns, not designed to provide structural support for the tubes. The batwing supports are designated BW1 (hot side) and BW2 (cold side).

Vertical Straps

The vertical straps (VS) and their associated support grids, provide vertical support for the tubes in the horizontal run at the upper region of the steam generators. The VS3 and VS5 are gridded from structural support straps that are attached to "I" beams in the upper head. The other vertical supports float, and are not attached to any "I" beams. The VS configuration provides vertical stabilization for the tubes (see Figure XII-4).

5. **Flow Paths**

There are two flow paths associated with a pressurized water reactor (PWR) steam generator design. On the primary side (tube 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.

On the secondary (shell side) flow paths (See Figure XII-5), feedwater is injected into the steam generator via the downcomer and the economizer flow nozzles. The quantity of flow through each path depends on the reactor power level of the operating unit.

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 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.

6. **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. Both the hot leg side and the cold leg side (economizer) have blowdown capability. 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.

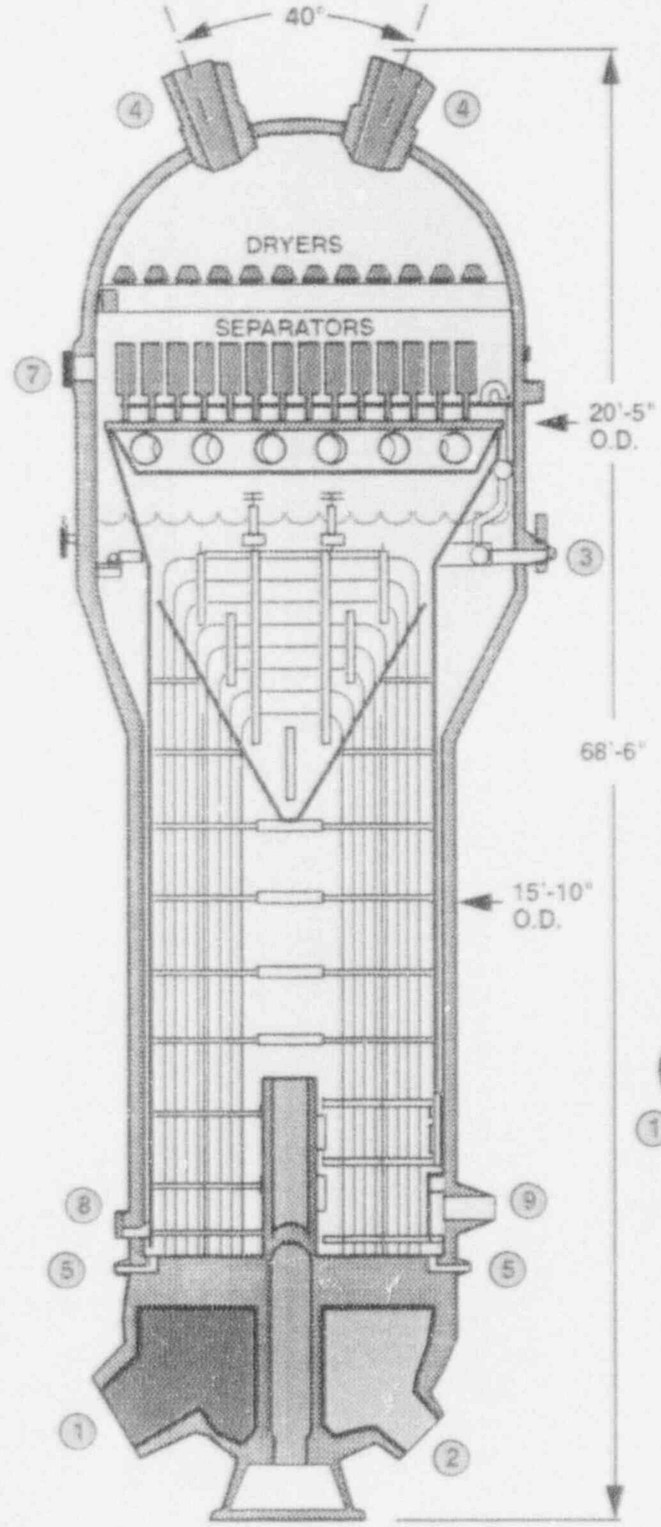
7. **Steam/Moisture Separation**

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 steam quality of 99.75%. To remove the required moisture, the System80 steam generators employ two stages of moisture separation: centrifugal separators and steam dryers.

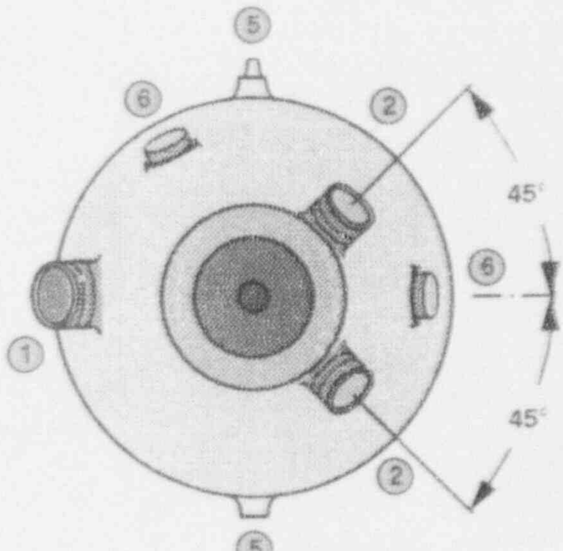
The first phase of moisture removal is accomplished by 194 centrifugal separators located on the SG can deck. The System80 moisture separator cans are provided with stationary spinner blades which impart a centrifugal motion to the steam/water mixture. The heavier water is thrown to the surface of the can 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 from this phase drops back into the separator region and is recirculated though the steam generator via spillover from the can deck (see Figure XII-5).

FIGURE XII-1

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

FIGURE XII-2

SYSTEM 80 STEAM GENERATOR TUBES

TRIANGULAR PITCH CONFIGURATION

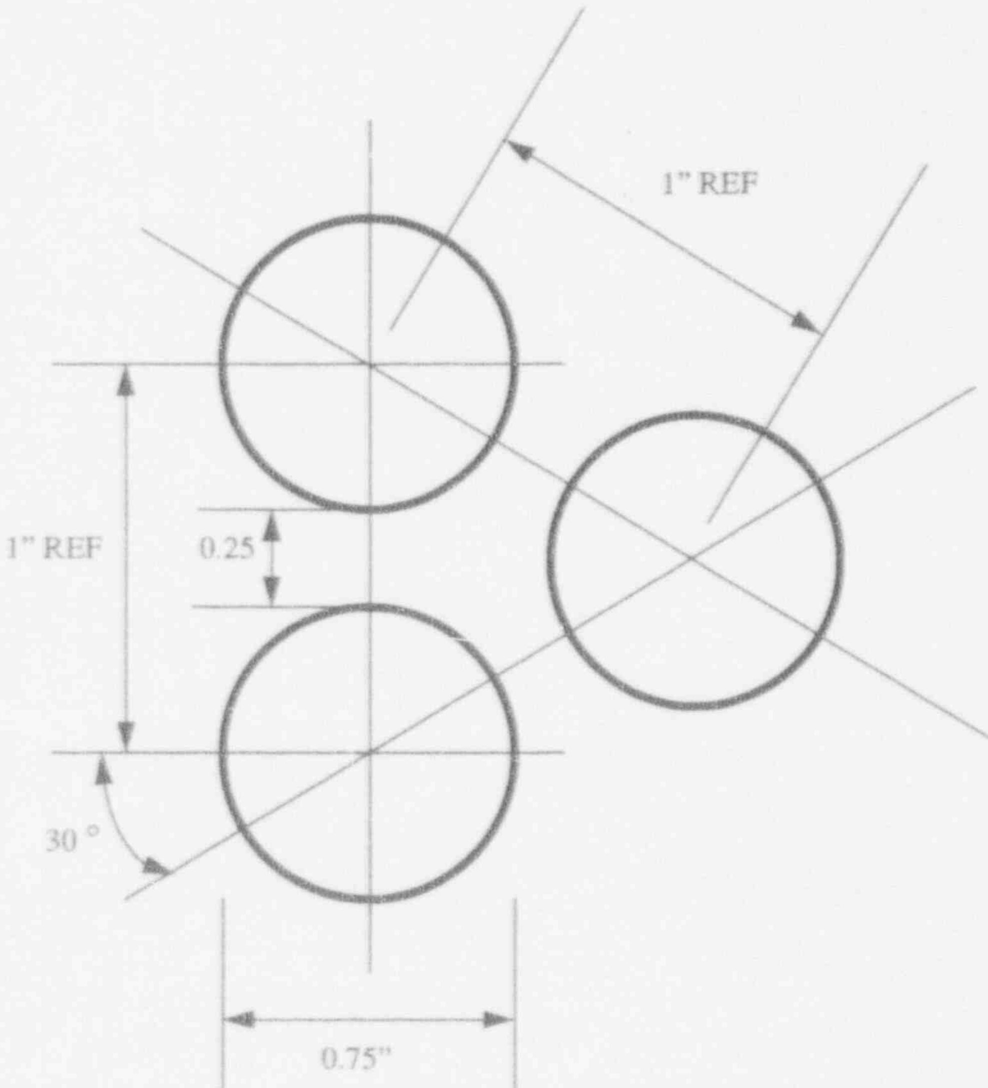


FIGURE XII-3

CE SYSTEM 80 STEAM GENERATOR TUBE SUPPORT DIAGRAM

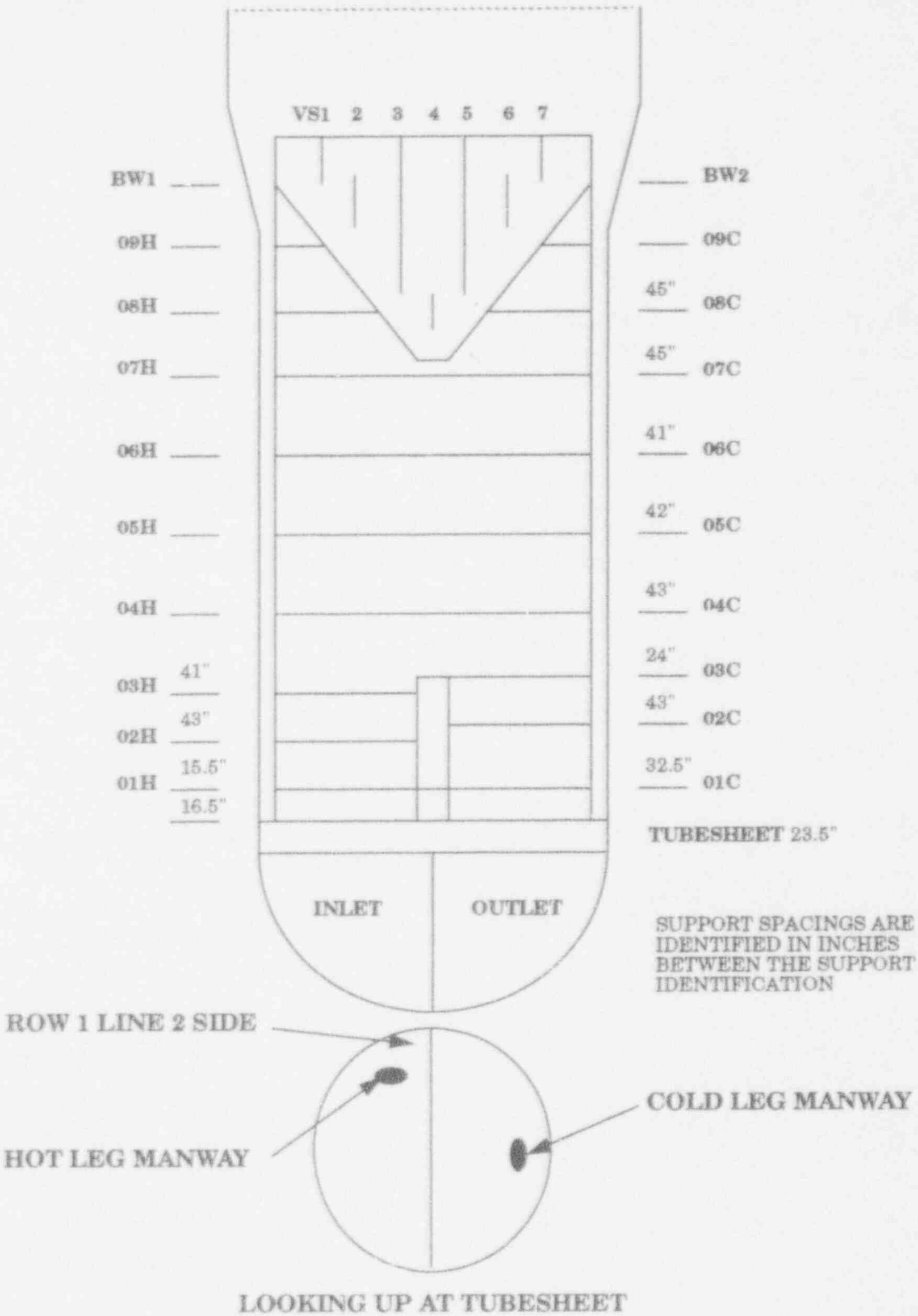


FIGURE XII-4

Palo Verde Upper Tube Bundle Supports

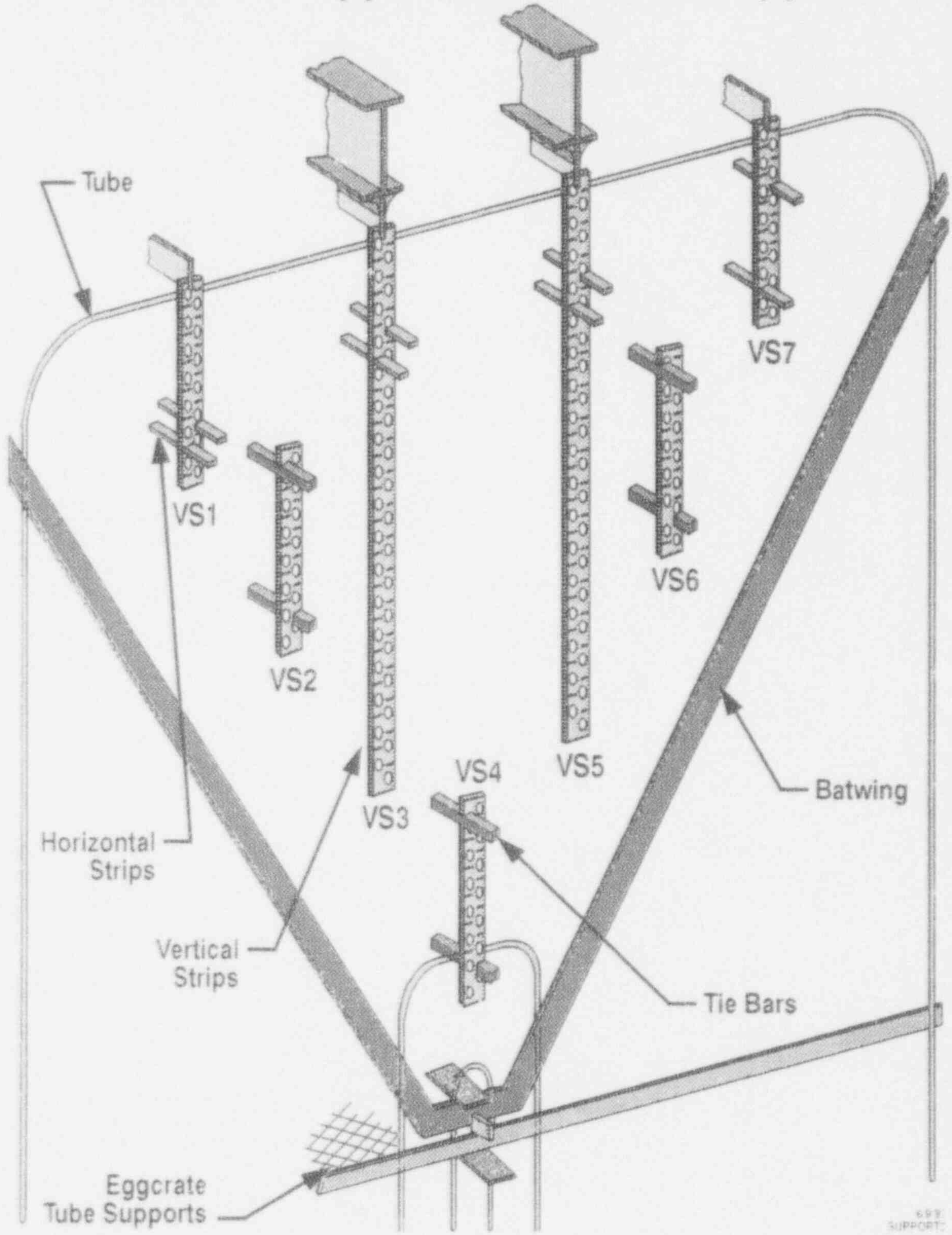
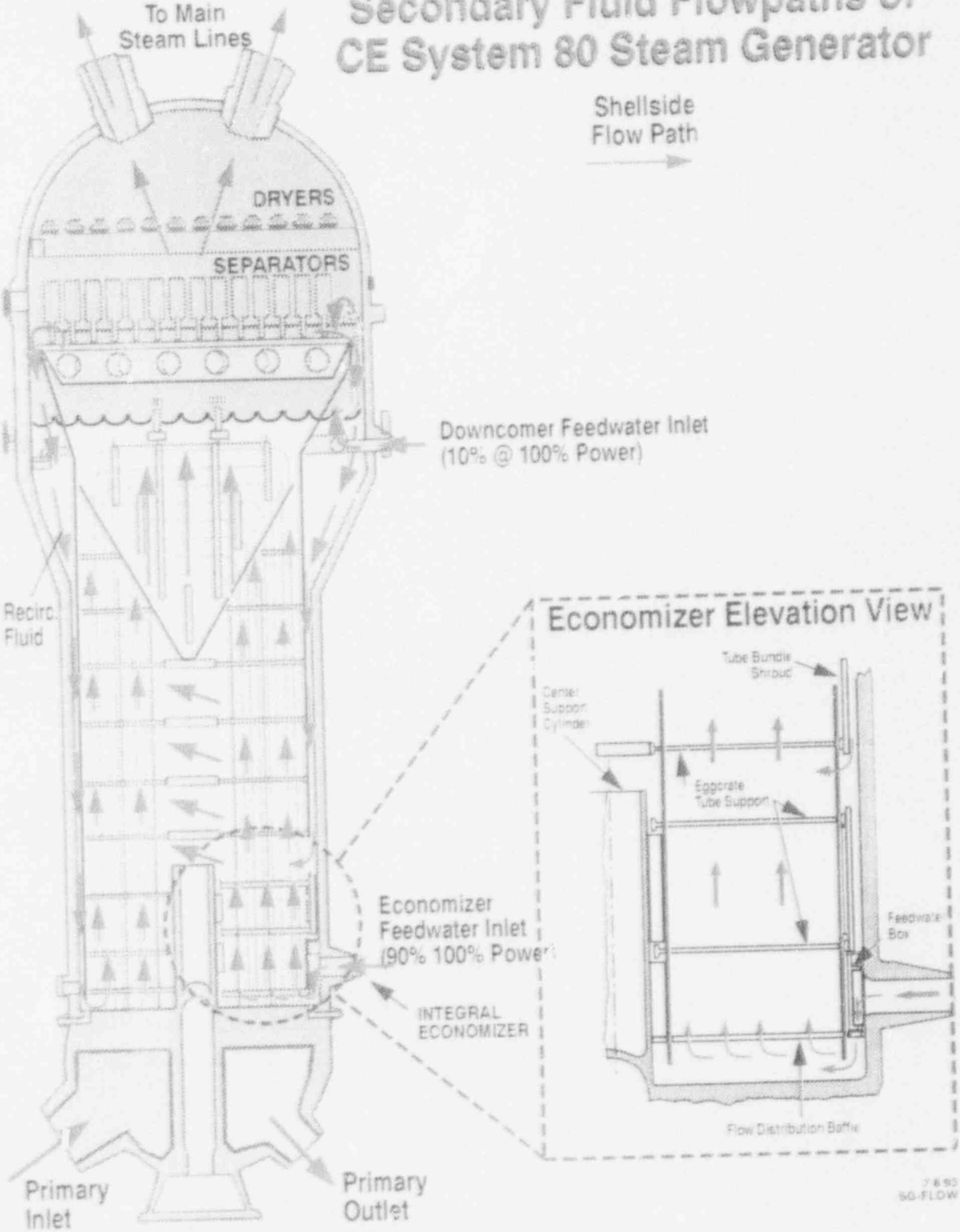


FIGURE XII-5

Secondary Fluid Flowpaths of CE System 80 Steam Generator



7 8 93
SG-FLOW

C. Eddy Current Reports

The following tables of eddy current indications are attached.

Table XI-1	Circumferential Indications, SG 11
Table XI-2	Circumferential Indications, SG 12
Table XI-3	Wear Indications >35%, SG 11
Table XI-4	Wear Indications >35%, SG 12
Table XI-5	Single Volumetric Indications Within "Bobbin" Arc, SG 11
Table XI-6	Single Volumetric Indications Within "MRPC" Arc, SG 11
Table XI-7	Single Volumetric Indications Within "MRPC" Arc, SG 12

Note 1: The "MRPC" arc is the area of 1800 tubes included in the original MRPC scope. The "Bobbin" arc is a buffer region of 2000 tubes surrounding the "MRPC" arc. The data provided is from the 08H through the first vertical support. See Figure IV-5.

Note 2: No axial indications were found outside the tubesheet area.

Note 3: There were no SVIs within the "bobbin" arc of SG 12.

TAP' E XI-1					
CIRCUMFERENTIAL INDICATIONS, SG 11					
Row	Column	Hot or Cold Leg	Location	ECT Call	Length (in.)
77	16	H	TSH-0.30	SCI	0.34
50	75	H	TSH-0.15	SCI	0.44
52	79	H	TSH-0.15	MCI	0.91
52	81	H	TSH-0.23	SCI	0.86
52	83	H	TSH-0.08	SCI	0.41
55	90	H	TSH-0.09	SCI	0.34
12	169	H	TSH-0.18	SCI	0.31

TABLE XI-2					
CIRCUMFERENTIAL INDICATIONS, SG 12					
Row	Column	Hot or Cold Leg	Location	ECT Call	Length (in)
22	55	H	TSH+0.00	SCI	0.55
23	56	H	TSH+0.11	SCI	1.32
23	60	H	TSH-0.02	SCI	0.99
25	60	H	TSH-0.01 TSH+0.11	SCI	1.22 0.26
35	60	H	TSH-0.04 TSH-0.04	SCI	1.06 0.25
39	60	H	TSH+0.00	SCI	0.90
137	60	H	TSH-0.29	SCI	0.68
32	61	H	TSH-0.06	SCI	0.40
34	61	H	TSH-0.03	SCI	0.38
36	61	H	TSH+0.09	SCI	0.75
44	61	H	TSH+0.00	SCI	0.32
35	62	H	TSH+0.16	SCI	0.21
43	62	H	TSH+0.11	SCI	0.27
47	62	H	TSH-0.01	SCI	1.15
30	63	H	TSH-0.03	SCI	0.48
29	64	H	TSH-0.10	SCI	0.31
53	64	H	TSH-0.02	SCI	0.60
28	65	H	TSH+0.00	SCI	0.29
51	66	H	TSH+0.12	SCI	0.24
34	67	H	TSH+0.06 TSH+0.11	SCI	0.18 0.28
38	67	H	TSH+0.13	SCI	0.23
40	67	H	TSH+0.06	SCI	0.24

TABLE XI-2 (continued)					
CIRCUMFERENTIAL INDICATIONS, SG 12					
Row	Column	Hot or Cold Leg	Location	ECT Call	Length (in)
39	68	H	TSH+0.09	SCI	0.21
43	68	H	TSH+0.02 TSH+0.22	SCI	0.45 0.27
51	68	H	TSH+0.18	SCI	0.13
45	70	H	TSH+0.11	SCI	0.42
42	71	H	TSH+0.13	SCI	0.26
44	71	H	TSH+0.07	SCI	0.22
52	71	H	TSH+0.28	SCI	0.45
54	71	H	TSH-0.04	SCI	1.67
56	71	H	TSH-0.12 TSH+0.34	SCI	0.34 0.45
57	72	H	TSH+0.23	SCI	0.33
54	73	H	TSH-0.02 TSH-0.02 TSH-0.02 TSH-0.02	SCI	0.51 0.30 0.43 0.38
60	73	H	TSH-0.08	SCI	0.28
43	74	H	TSH+0.18	SCI	0.43
59	74	H	TSH+0.21	SCI	0.15
61	74	H	TSH+0.16	SCI	0.21
42	75	H	TSH+0.05	SCI	0.35
46	75	H	TSH+0.14	SCI	0.25
48	75	H	TSH-0.04	SCI	0.16
54	75	H	TSH+0.00 TSH+0.23	MCI	2.01 0.28
56	75	H	TSH+0.21	SCI	0.55

TABLE XI-2 (continued)					
CIRCUMFERENTIAL INDICATIONS, SG 12					
Row	Column	Hot or Cold Leg	Location	ECT Call	Length (in)
58	75	H	TSH+0.19	SCI	0.67
62	75	H	TSH+0.26 TSH+0.26	SCI	0.94 0.28
64	75	H	TSH+0.23	SCI	0.30
49	76	H	TSH-0.02	SCI	0.50
53	76	H	TSH-0.02 TSH+0.11	SCI	0.32 0.18
55	76	H	TSH+0.01	SCI	0.79
59	76	H	TSH+0.16 TSH+0.16	MCI	0.55 0.33
61	76	H	TSH+0.14	SCI	0.45
36	77	H	TSH+0.21	SCI	0.25
48	77	H	TSH+0.10	SCI	0.61
58	77	H	TSH+0.00	SCI	0.58
60	77	H	TSH-0.07 TSH+0.26	SCI	0.88 0.57
49	78	H	TSH+0.04 TSH+0.18	SCI	0.76 0.35
51	78	H	TSH-0.02	SCI	0.41
53	78	H	TSH-0.03	SCI	0.87
63	78	H	TSH+0.05	SCI	0.38
65	78	H	TSH+0.15	SCI	0.48
69	78	H	TSH-0.02	SCI	0.30
48	79	H	TSH+0.02	SCI	1.33
54	79	H	TSH-0.05	SCI	0.33
60	79	H	TSH+0.21	SCI	0.21
57	80	H	TSH+0.28	SCI	0.35

TABLE XI-2 (continued)					
CIRCUMFERENTIAL INDICATIONS, SG 12					
Row	Column	Hot or Cold Leg	Location	ECT Call	Length (in)
54	81	H	TSH+0.12	SCI	0.44
53	82	H	TSH+0.15	SCI	0.49
67	82	H	TSH+0.14	SCI	0.71
48	83	H	TSH+0.01	SCI	0.27
47	84	H	TSH+0.00	SCI	0.28
65	84	H	TSH+0.13 TSH+0.13 TSH+0.13	SCI	0.43 0.36 0.22
64	85	H	TSH+0.18	SCI	0.79
47	86	H	TSH+0.03	SCI	0.50
69	86	H	TSH-0.01	SCI	0.60
54	87	H	TSH-0.01	SCI	0.58
64	87	H	TSH+0.13	SCI	0.42
64	89	H	TSH-0.07	SCI	0.24

TABLE XI-3				
WEAR INDICATIONS > 35%, SG 11				
Row	Column	Hot or Cold Leg	Location	% Wear
84	19	C	VS5+0.85	37
81	60	H	VS3+0.91	47
155	82	H	BW1+1.93	50
154	83	C	VS7-0.84	36
156	87	H	BW1+1.37	40
159	94	C	VS7+1.27	37
159	96	H	BW1-1.66	37
157	110	C C	VS7+0.83 BW2-1.86	37 41
83	134	H	VS3+1.00	42
76	159	H	VS3+0.93	38
81	168	C	VS5+0.12	36
78	169	H	VS3-0.92	42

TABLE XI-4				
WEAR INDICATIONS > 35%, SG 12				
Row	Column	Hot or Cold Leg	Location	% Wear
1	2	C	02C-0.71	37
73	28	H	VS3+0.57	48
85	74	C	VS5-0.84	36
159	102	C	BW2+1.97	40
158	103	C	BW2+1.93	43
117	106	H	09H+1.53	37
158	107	C	VS7+0.74	44
154	119	C	05C-1.00	39
101	132	H	BW1+2.72	36
84	133	H	VS3-0.59	37
144	135	C	03C+0.80	38
76	141	H	VS3-0.86	36
79	148	C	VS5+1.03	39
71	154	H	08H-0.91	39
84	155	H	VS3-0.84	37
73	160	C	VS5+1.05	45
12	189	C	05C+0.16	36

TABLE XI-5						
SINGLE VOLUMETRIC INDICATIONS WITHIN "BOBBIN" ARC, SG 11						
Row	Column	Hot or Cold Leg	Location	ECT Call	Deposit	Bowing
116	83	H	BW1+1.20	SVI	Yes	Yes
97 *	138	H	BW1+2.85	SVI	Yes	No

* Tube R97C138 is included in this table as an SVI related to arc conditions although the tube is located one tube outside the "bobbin" arc.

TABLE XI-6						
SINGLE VOLUMETRIC INDICATIONS WITHIN "MRPC" ARC, SG 11						
Row	Column	Hot or Cold Leg	Location	ECT Call	Deposit	Bowing
149	88	H H H H	08H +12.00 to +18.73 08H +21.55 to +22.20 08H +23.26 to +28.37 08H +33.12 to +37.62	SVI	No	No

TABLE XI-7						
SINGLE VOLUMETRIC INDICATIONS WITHIN "MRPC" ARC, SG 12						
Row	Column	Hot or Cold Leg	Location	ECT Call	Deposit	Bowing
100	31	H	BW1+3.15	SVI	Yes	No
122	101	H	BW1+0.57	SVI	Yes	Yes
148	115	H	BW1 +0.50 to +1.00	SVI	Yes	No