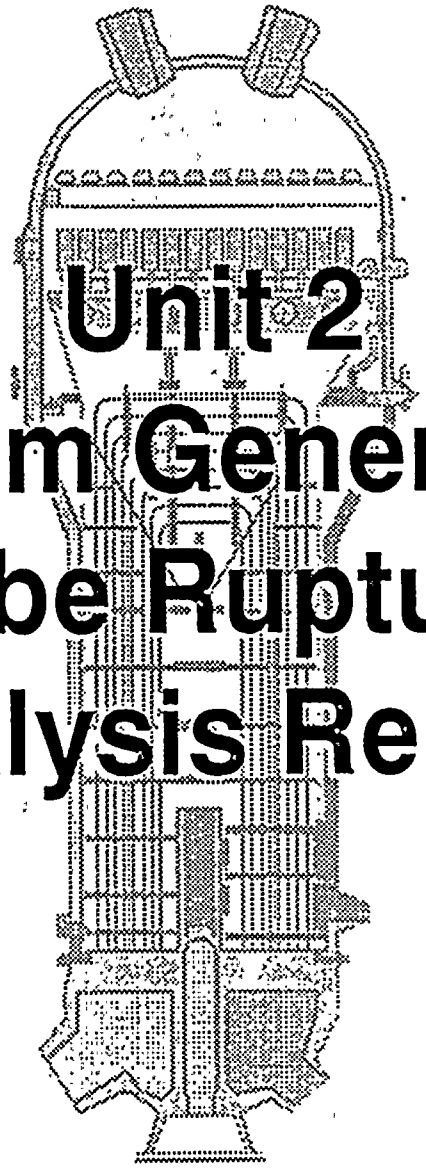
Palo Verde Nuclear Generating Station



Unit 2 Steam Generator Tube Rupture Analysis Report

July 1993

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I. EXECUTIVE SUMMARY

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

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

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

Specifically, eight (8) tubes were removed (including the lower portion of the ruptured tube) from SG 22 for metallurgical and chemical examinations. Additionally, a comprehensive review of fabrication, operation and chemistry history was performed to determine if an anomaly contributing to the failures existed. Industry developed thermal hydraulic codes were also utilized to evaluate steam quality and deposit distribution in the tube bundle. Based on the information resulting from these activities the Task Force developed the most probable causal factors for tube degradation which led to the failure of tube R117C144.

After considerable evaluation the Root Cause of Failure (RCF) investigation determined the failure mechanism leading to the SGTR event was due to IGA/IGSCC which occurred as a result of tube-to-tube crevice formation. The crevice, together with the consequential heat flux, led to an aggressive environment under a tenacious ridge deposit. As a consequence, a long deep crack, initiating under the ridge deposit led to loss of structural integrity under normal operating conditions. Several additional contributing factors such as: increased sulfate levels due to resin intrusion, a less than standard microstructure in R117C144, the likelihood of cold working due to tube surface scratches, and increased susceptibility to contaminant concentration in the upper region of the tube bundle were identified by the Task

Force. Since it was not possible to weight the relative importance of each contributor, APS intends to continue the investigative effort to address each item.

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

An evaluation was performed by the Task Force to determine the appropriate length of the next operating period which would provide reasonable assurance that the Regulatory Guide (RG) 1.121 limits for steam generator tube integrity are maintained. This effort required an analysis of probable crack growth rate, determination of maximum allowable flaw size, and selection of a beginning-of-cycle (BOC) crack depth based on ECT detectability. The results indicate the need for a midcycle shutdown for additional eddy current inspection after six months of power operation. Additionally, a probabilistic analysis of crack growth rate confirms a 95% confidence with a 95% probability that RG 1.121 limits will not be exceeded after six months of full power operation.

Finally, the safety significance of leaving undetected defects through the next operating cycle was evaluated by APS. The screening criteria defined in 10CFR50.59 was utilized to evaluate potential unresolved safety questions associated with IGA/IGSCC attack.The proposed six month operating cycle will assure that the structural integrity of the steam generator tubes will be maintained, and that no unresolved safety issue exist.

II. EVENT DESCRIPTION AND SAFETY ASSESSMENT

A. Event Description

On March 14, 1993, at approximately 0434 MST, Palo Verde Unit 2 was in Mode 1 (POWER OPERATION), operating at approximately 98 percent power, when a steam generator tube ruptured in Steam Generator 22. At approximately 0447 MST, the reactor was manually tripped due to low pressurizer level and pressure.

Approximately 22 seconds later, valid actuations of the Safety Injection Actuation System (SIAS) and the Containment Isolation Actuation System (CIAS) occurred due to low pressurizer pressure. Pressurizer level was restored and a controlled cooldown and depressurization of the Reactor Coolant System (RCS) was conducted in accordance with approved procedures. A steam generator tube rupture in Steam Generator 22 was diagnosed, and the steam generator was successfully isolated.

This event was investigated in accordance with the Palo Verde Nuclear Generating Station Incident Investigation Program. In response to the event, APS formed a Steam Generator Tube Rupture Task Force to determine the root cause of the tube failure, and to specify evaluation, remedial and restart recommendations to PVNGS plant management and the Nuclear Regulatory Commission.

A safety limit evaluation was also performed as part of the PVNGS Incident Investigation. The evaluation determined that the plant responded as designed, that no safety limits were exceeded, and that the event was bounded by current safety analyses. Specific details regarding operator and equipment response are contained in IIR 2-3-0112, Unit 2 Manual Reactor Trip Following a Steam Generator Tube Rupture.

B. Safety Assessment

Nuclear Fuel Management personnel performed a safety assessment of the event and determined that the equipment and systems assumed in the Updated Final Safety Analysis Report (UFSAR) Chapter 15 were functional and performed as required. Scenarios defined in UFSAR Chapter 6 concerning loss of coolant accidents were not challenged during the event.

The safety assessment concluded that the event did not result in a transient more severe than those previously analyzed. This determination was based on an evaluation of actual event parameters and dose assessments, compared to those contained in UFSAR, Section 15.6.3.1, Combustion Engineering Standard Safety Analysis Report, Section 15.6.3.2. and the SGTR with Loss of Offsite Power (SGTRLOP) reanalysis which was performed in accordance with Revision 1 to the "Steam Generator Tube Rupture Analysis Concerns and Justification for Continued Operation" (JCO 91-02-01). There were no adverse safety

consequences or implications as a result of this event. This event did not adversely affect the safe operation of the plant or the health and safety of the public. The 2-hour exclusion area boundary thyroid dose was calculated to be less than 0.3 millirem and the 8-hour low population zone thyroid dose was calculated to be less than 0.04 millirem. These doses are much less than the Standard Review Plan 15.6.3 acceptance criteria of 30 Rem thyroid.

During the safety assessment of this event, concerns were raised regarding the differences in the timing of operator actions to isolate the ruptured steam generator as assumed in UFSAR Chapter 15 SGTR event, and the timing of those actions in the actual event. Similar concerns, however, were previously identified in October, 1991, as documented in JCO 91-02-01. In response to these concerns, the primary system equilibrium dose equivalent Iodine-131 (DEQI131) is currently limited to 0.6 uCi/gm in all three units, and a SGTRLOP reanalysis has been performed to verify that a more conservative treatment of operator timing, combined with the Technical Specification activity limits (1.0 and 0.1 uCi/gm for primary and secondary activity respectively), would not result in dose consequences greater than the acceptance criteria. The reanalysis is the most current analysis for a SGTR or SGTRLOP event. The results of the reanalysis are within the Standard Review Plan 15.6.3 acceptance criteria of 30 Rem thyroid.

The safety assessment of the event concluded that the longer interval required for isolation of the ruptured steam generator was compensated for by the low primary and secondary activities in effect at the time of the rupture. However, a supplemental evaluation was performed using a "best-estimate" transient evaluation code to evaluate the dose consequences associated with a steaming interval consistent with the actual event, with the affected generator steaming directly to the atmosphere and not through the condenser, and with DEQI131 activity levels at the Technical Specification limits. The resulting dose consequences for this supplemental case were also well within the acceptance criteria of 30 Rem thyroid and are bounded by the SGTRLOP reanalysis.

C. Leakage Monitoring - Cycle 4

A review of the leakage trending which occurred during Cycle 4 was conducted by APS. The results of the review, when compared to number of through-wall indications found during eddy current testing and the tube examination results, did not provide conclusive evidence of a slow, stable increase in primary to secondary leakage. Additionally, PVNGS has had a history of welded tube plug leakage. Therefore, the quantity of leakage monitored immediately prior to the tube rupture event may not have been from the ruptured tube R117C144. A chronology of the leakage indications and observations during Cycle 4 as described in Incident Investigation Report IIR 2-3-0112 is presented below:

- **July 2, 1992**

  Unit 2 began measuring detectable levels of tritium (H-3) at a concentration of 1E-5 µCi/cc in the secondary plant. No other nuclides, which would be typically detected in the presence of primary-to-secondary leakage (such as iodine or xenon isotopes), were identified. The initial leak rates were calculated per 74CH-9ZZ66 at approximately 0.69 and 1.17 gallons per day in SG 1 and SG 2, respectively. Chemistry Action Document (CAD) 2-92-0027 was issued to monitor Blowdown Monitors RU-4, RU-5, and Condenser Off-gas Monitor RU-141's ten minute and hourly trends every four hours to note any increases in activity. Trend information was logged in the Unit 2 Radiation Monitoring System (RMS)/Effluents Shift Log.

- **July 2, 1992 to February 4, 1993**

  CAD 2-92-0027 remained in place. Tritium concentrations remained in the range of 1E-6 µCi/cc to 5E-6 µCi/cc.

- **February 4, 1993**

  RU-4 and RU-5 setpoints were lowered from a UFSAR value of 4E-6 µCi/cc to more closely monitor any minor increases in steam generator activity. Although the setpoints were lowered, the change was statistically insignificant when compared to typical background readings of 1E-6 µCi/cc for these monitors.

- **February 20, 1993**

  Iodine -131 (I-131) was first detected in SG 2 blowdown at approximately 3E-8 uCi/ml. No increase in H-3 concentrations were noted at the time.

- **February 20, 1993 to February 27, 1993**

  On SG 22, I-131 concentrations trended up from 3E-8 µCi/cc to 1E-7 µCi/cc. RU-4 and RU-5 trends also increased.

- **February 28, 1993**

  CAD 2-93-0018 was issued to increase monitoring of RU-4, RU-5 and RU-141 trends to every two hours.

- **March 1, 1993**

  Leak rate stabilizes. RU-4 and RU-5 setpoints raised in accordance with 74RM-9EF42 due to higher equilibrium concentrations in the steam generators.

- **March 3, 1993**

  Use of I-131 to calculate steam generator leak rate was initiated. Prior to that time, tritium was used for leak rate calculations with typical values of 0.5 to 3 gallons per day. Initial I-131 leak rate calculations indicated about 8 gallons per day. Spikes were observed due to charging pump surveillance testing (ST) leading to a momentary increase in RCS pressure.

- **March 9, 1993**

  RU-4 and RU-5 setpoints were raised after monitor readings and steam generator I-131 activities stabilized.

- **March 9, 1993 to March 13, 1993**

  For SG 22, steam generator tube leak rates were calculated by the I-131 method and were fairly constant at about 10 gallons per day.

- **March 13, 1993 to March 14, 1993**

  RU-4, RU-5 and RU-141 trends were reviewed at two hour intervals. The following log entries were made by the onshift RMS technicians:

  (March 13, 1993)

  0640 RU-141 trends stable, RU-4, 5 trends increasing slightly

  0845 RU-141 trends stable, RU-4, 5 trends slight steady increase

  1040 RU-141 trends stable, RU-4, 5 trends still slight increase

  1255 RU-141, 4,5 trends stable

  1445 RU-141, 4, 5 trends stable

  1650 RU-4, 5, 141 trends stable

  1840 Reviewed RU-4, 5, 141 trends, console log, and DCU displays (no trend changes noted in log).

  2050 Reviewed RU-4, 5, 141 trends, console log, and DCU displays (no trend changes noted in log).

  2340 Reviewed RU-4, 5, 141 trends, console log, and DCU displays (no trend changes noted in log).

(March 14, 1993)

0245 Reviewed DCU displays, RU-4, 5, 141 trends and console log (no trend changes noted in log)

- **March 14, 1993**

  Post incident review of 10 second monitor readings, obtained from ERFDADS, for RU-4, RU-5 and RU-141 indicated no discernible increasing or decreasing trends from 0300 until the rupture occurred. Only RU-141 readings increased significantly, by a factor of ten, within minutes following the initiation of the rupture.

As described above, Unit 2 had been monitoring small primary-to-secondary leakage since July, 1992. Secondary radiation monitors began to alarm in February 1993. The alarms were not long in duration but were consistently received during small reactor coolant system pressure transients, such as when shifting charging pumps. Beginning March 3, 1993 steam generator I-131 concentrations became large enough to calculate and track leak rate in gallons per day. The leak rate was calculated by the I-131 method at least 19 separate times between March 2 and March 13, 1993. During that time period, the leak rate was nominally 20 gallons per day. Increases in leak rate levels were noted during plant changes in power levels and high rate blowdowns. However, the calculated leak rates were decreasing for two days prior to the incident. Leak rates were discussed at the chemistry shift turnovers and daily plant management meetings.

A post review of the leak rate data was performed to validate the actual leak rate as well as to assess the various leak rate determination methodologies. During this review, deficiencies were identified with the Iodine method of leak detection and trending. It is the APS position that gas grab samples taken at the condenser vacuum exhaust will provide the most accurate estimation of actual leak rate. Although this method was not utilized during Cycle 4, the data has been reconstructed and is presented in Figure II.a.

The tritium leak rate data has also been reconstructed, and provides the best estimation of actual leak rate for the period between February 14, 1993 and March 14, 1993. This leak rate data is presented in Figure II.b, and reflects a stable leak rate of approximately 20 gallons per day prior to the steam generator tube rupture.

III. STEAM GENERATOR DESIGN

A. Design Data and Performance Parameters

Each Palo Verde Unit utilizes two steam generators 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[1], and are currently the only operating units of this design (System80). The steam generator arrangement is shown in Figure III-a.

The steam generators are designed to transfer 3817 MWt from the reactor coolant system to the secondary system, producing approximately 17.2×10^6 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:

1. In 1989, Asea Brown Boveri (ABB) purchased Combustion Engineering, Inc. Throughout this report, ABB-Combustion Engineering will be referred to as Combustion Engineering or CE.

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°
Design Thermal Power	3817 MW_t
Coolant Flow in Each Loop	82×10^6 lbm/hr
Normal Operating Pressure	2250 psia
Normal Operating SG Inlet Temperature	621.2°F
Normal Operating SG Outlet Temperature	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 Temperature 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

B. Steam Generator Materials

The steam generator's pressure containing members are constructed of low alloy steel (P3). The tubesheet is a 23.5" thick low alloy steel base, with 1/4" 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.

C. Tube Design

Each steam generator contains 11,012 tubes which are 3/4" OD, and have a nominal wall thickness of 0.042" 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 III-b. 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 (4-1/4") 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.

D. 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 minium 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 III-c 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, as shown in Figure III-d. 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. (See Figure III-e)

- **Batwings**

  Batwing stabilizers horizontally support the bends in the U-tubes. (See Figure III-f) 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 III-g)

E. 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 III-h), 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 (Figure III-i) 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.

F. Blowdown

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

G. SG Level Control

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

modes, single element and three element control. The modes are dependent on the reactor power level.

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

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

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

H. 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 III-h)

I. Steam Generator Circulation Ratio

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

a. downcomer water level - higher water levels increase CR

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

c. steam pressure - higher pressures decrease CR

d. tube bundle diameter - larger diameter decreases CR

e. primary moisture separator duty - higher duty decreases CR

Typical industry circulation ratios range from 3:1 to 4:1. The lower range value for the System80 steam generator can be accounted for by inherent design features, such as, bundle size and steam pressure. The controlling parameter for internal SG circulation is the difference in hydraulic head (feet of water at the average density) between the downcomer annulus as compared to the fluid in the tube bundle and above through the steam separators. When the total pressure drop within the recirculating flow path equals the driving head, equilibrium is attained. Since the secondary side of the steam generator operates in the saturated steam regime, higher steam pressure is associated with higher fluid saturation temperatures and corresponding lower liquid densities. Therefore, the downcomer driving head is reduced at higher steam pressures leading to a lower circulation ratio.

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

IV. ROOT CAUSE OF FAILURE PROGRAM

The focus of this Root Cause of Failure (RCF) investigation was to determine the cause(s) for the fish-mouthed axial cracking which occurred in Unit 2 Steam Generator 2 (SG 22), tube R117C144. Based on early eddy current testing (ECT) and video evidence, the tube failure was determined to be the result of outside diameter (OD) initiated axial cracking. Based on the facts and information available early in the investigation, the Steam Generator Tube Rupture Task Force developed a flow chart identifying possible failure modes (See Figure IV-a, SGTR Event Failure Modes). Based on the initial findings, APS identified four possible failures modes:

Outside Diameter Stress Corrosion Cracking - Chemistry

Flow Oscillation Induced Cracking- Fatigue

Tube Locking Induced Cracking - High Residual Stress

Egg Crate Support Misalignment Induced Cracking - High Residual Stress

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

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

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

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

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

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

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

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

V. STEAM GENERATOR OPERATING HISTORY

A. Steam Generator Chemistry

1. Introduction

The chemistry control program at Palo Verde was originally developed under the guidance of CENPD28. The program's purpose was to establish specific limits for impurities in the steam generators, 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 PWR Secondary Water Chemistry Guidelines, as well as the incorporation of lessons learned at PVNGS and other domestic and international utilities. Initially, action was taken when a Unit's chemistry exceeded the stated guidelines. In late 1989, an ALARA (As Low As Reasonably Achievable) chemistry philosophy was implemented in order to keep the contaminants to as low a level as practical. In an attempt to improve the chemistry in the crevice region of the steam generators, this ALARA principle was enhanced with "min/max" chemistry control. Recent changes in chemistry control have been directed toward the reduction of ionic and corrosion product transport to the steam generators. Significant progress has been seen in 1993 for both areas in Units 1 and 3.

For the purpose of evaluating potential failure modes for the tube failure event, a detailed review was conducted to assess the effect of plant bulk chemistry, contaminant intrusions, predicted local crevice conditions, layup conditions and changes to secondary chemistry operational practices, to assess their effect on plant chemistry.

2. Unit 2 Secondary Water Chemistry

Plant bulk water chemistry (daily operating chemistry parameters) was maintained in accordance with plant procedures, CE Owners Guideline and EPRI Industry Guidelines. Since 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 2 was consistent with Units 1 and 3 data. The operating parameter that best depicts the steam generator bulk chemistry condition is the molar ratio (the 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 steam generator blowdown, while consistently within EPRI and CEOG specifications, were higher (on an equivalent weight basis) than chloride levels.

Since 1993, however, the molar ratio trend in Units 1 and 3 have reflected a near-neutral or slightly acidic SG bulk water chemistry and the molar ratio trend in Unit 2 prior to shutdown, indicated a caustic bulk water environment. Unit 2's bulk water condition was verified by the pulled tube analysis that confirmed the presence of a caustic crevice environment. The higher operating molar ratio was also reflected by the high concentrations of sodium (400 ppb) when all three units downpowered to 75% power. This level of sodium hideout return has not been observed in Westinghouse designed steam generators and may be specific to steam generators with eggcrate support design.

Despite having a common feedwater source, operational bulk water chemistry differs within a particular unit. This difference may be due to blowdown efficiency or steaming rates, however, operational bulk water chemistry is maintained through blowdown flow rates. The abnormal blowdown flow (measured in 1992) was two times higher for SG 22 than SG 21, however both had equivalent normal blowdown. The difference in blowdown flow does not appear to have contributed to the larger degree of tube damage in SG 22.

Prior to March 1993, operating bulk water chemistry was monitored via the hotleg sample point. Since then, the downcomer sample point has been used to monitor impurity levels in Units 1 and 3. Due to dilution of the blowdown sample with feedwater, the downcomer sample impurity concentrations are approximately a factor of six times higher than hotleg sample concentrations and appear to be more representative of tube bundle chemistry conditions.

The level of corrosion product transport in the secondary bulk water was also reviewed by the Task Force. Corrosion products of concern to the investigation were iron and copper levels. A formal study of iron transport throughout the secondary system was conducted for Unit 2 in 1991, and determined that under optimal conditions with condensate polishers in service, and a feedwater pH of 9.15, three (3) pounds of iron per day would accumulate in each steam generator. Based on the findings of the study, over 5,000 pounds of iron could have accumulated per steam generator to-date. Access for sludge lancing has not been previously available (Access ports were installed during U2R4), however ECT results indicate minimal sludge accumulations. Therefore, it is assumed that the iron deposited on tubes and tube supports. Based on the total surface area of the tube bundle, this quantity of corrosion product transport would result in a 2-4 mill general deposit after four cycles of operation.

PVNGS essentially operates as a copper free secondary, therefore a formal copper transport study was not performed in Unit 2 during its operation. However soluble and particulate copper concentrations were recently measured in Units 1 and 3. Typically, total copper concentrations were measured at 15 parts per trillion (ppt) in the final

feedwater with the condensate demineralizers bypassed and the feedwater pH maintained at 9.8 with ETA/hydrazine and ammonia/hydrazine chemistry control. Under the conditions identified above, approximately 1 pound of copper would be transported to each steam generator annually. Actual copper transport quantities should have been less than one (1) pound per year in all three units due to the historically lower feedwater pH values employed at PVNGS.

In summary, the review of bulk water chemistry indicates that a caustic crevice environment was present in the Unit 2 steam generators. The high transport of iron projected above would support deposit formation as observed in the SG, while the apparent transport of copper was not sufficient to influence the SG corrosion rate.

3. **Chemistry Transients**

Operating chemistry data and shift logs were reviewed to determine if any abnormal occurrence of contaminant intrusion had occurred. Two specific event types were considered by the Task Force.

- **Condenser Leaks**

  - Based upon an engineering assessment of condenser tube leak events, (prior to 1988), Unit 2 experienced more condenser tube leaks than the other units (approximately two times the site average of 1.7 reported leaks per year).

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

  - A tube leak in Unit 2 during 1990 was particularly severe at an estimated 150 gpm. This event was contained by the condensate demineralizers.

- **Resin Intrusion**

  - A failure of service vessel (SV) "B" retention screen occurred in July 1991 at Unit 2. A similar problem occurred during January 1992 as a result of SV "E" retention screen problems. An indeterminate amount of resin was transported to the SG's, but the total volume was estimated to be a fraction of the resin used during the cycle.

  - Sulfate concentrations in blowdown samples did not increase following the July 1991 event. Due to the very high adsorption rate for sulfate, increases in blowdown concentrations would not necessarily be noted. Following the

January 1992 event, sulfate levels escalated to approximately five times the level in EPRI guidelines.

- Small quantities of resin were observed during visual inspections of SG 21 and SG 22 can decks. Approximately 1 gram of resin was present in the 10 ft^2 area vacuumed in SG 21.

- Tests performed on resin beads, obtained during the visual inspection, determined that the majority of the functional groups had been removed. This confirmed that the sulfate contribution to the SG had already occurred.

- Inspections of service vessels during U2R4 revealed damaged retention elements in several service vessels, as well as a damaged liner in one service vessel.

The resin intrusion in January 1992 increased the level of sulfate in the SG's in a short period of time. Retention screen and trap problems identified during the U2R4 inspection of all condensate demineralizers may be evidence that a chronic input of sulfate had occurred throughout the operating cycle. There were no other abnormal indications of a contaminant intrusion. EPRI (Resin and Ionics Leakage from Condensate Polishers with and without Inert Resin, NP-4521) estimated the annual resin leakage values to be 38 to 235 lbs.

- **Steam Generator Layup**

The layup conditions were reviewed for any impact on SG tube degradation. Unit 2 had experienced some periods when the SG were dry and/or without a nitrogen over pressure. Those transient layup conditions were minimized in Unit 2, and were not considered to have aggravated the SG tube condition.

4. Hideout Return Studies

Hideout return data is considered the most accurate indicator of the chemistry present within steam generator 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 Palo Verde units to determine what, if any, differences had existed between the hideout return characteristics of the six steam generators. A total of 53 shutdown data sets covering January 1987 through March 1993 were reviewed. Data prior to January 1991 were reviewed to determine peak concentrations observed during the shutdown. More recent hideout data was reviewed to calculate cumulative grams returned.

Prior to 1991, MULTEQ pH was not determined. The best comparison of historical data is the peak concentration data summarized in Figure V-a (upper table). The data included are as follows:

- The average of all chloride, sulfate and sodium peak concentrations observed during the shutdowns
- The calculated ratios of sodium divided by chloride plus sulfate (cation/anion balance)
- The calculated molar ratios of sodium divided by chloride.
- The ratio of each Units' SG 1 to SG 2 for each impurity (SG 1 divided by SG 2)

In addition, the hideout return data obtained in accordance with PVNGS Station Manual Procedure 74DP-9ZZ06, Hideout Return, was more extensive and provided for quantification of grams for all species of interest, and an estimation of crevice pH (MULTEQ). This data has been summarized in Figure V-a (bottom table) and includes:

- The average grams returned from each generator during the shutdown
- The MULTEQ predicted crevice pH during operation as determined from sodium, chloride, sulfate, calcium, magnesium, silica, potassium, etc.

The results of the hideout return studies have predicted local crevice conditions that are highly alkaline to caustic. The crevice condition would be influenced by large sodium return. Unit 2 has recorded the highest levels of sodium and sulfate return. Those findings are consistent with the primary causes of IGA found on the tubes. (See Figure V-a).

5. Hideout Return Data Review Observations

Based on a review of the hideout return data, the following observations are noted. This data summarizes the highly caustic environment and levels of significant contaminants in the SG's.

- The average peak sodium hideout return concentration was significantly higher in SG 22 than in SG 21 (270 ppb vs. 172 ppb). The other units did not show this large of a discrepancy of concentration between SGs in a unit.
- The average peak sodium hideout return concentration from SG 22 was higher than any other steam generator (See Figure V-a).

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

- The more recent hideout return data indicated Unit 2 experienced the highest return of sulfate and sodium, and the lowest return of chloride.

- MULTEQ calculated crevice pHs were historically identical in all three units (range 8.6 - 10.7). This was an alkaline-to-caustic pH. EPRI data suggested a greater than tenfold increase in SCC growth rate would occur as the pH level exceeded 9.0.

- The peak concentrations of sulfate, as well as the cumulative grams of sulfate returned, were high in all three units.

- The October 1991 Unit 2 hideout return study identified lead levels higher than had been subsequently seen in Units 1 and 3. The level of lead, however, is not considered to be a primary contributor to the IGA mechanism.

6. Recent Secondary Chemistry Control Changes

PVNGS chemistry 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 contaminant source input into the SGs. The following actions were conducted to reduce the sodium levels transported to the SGs;

- Removal of the cation heel (January 1989)

- Reduction in anion regeneration frequencies (November 1990)

- Performance of a second cation resin regeneration in each resin regeneration cycle (1992)

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

Other changes were also initiated in 1992. Feedwater pH was optimized to $\geq$9.15 with full flow condensate demins (previously operated at pH> 8.8) in order to reduce iron transport. In conjunction with the operational changes to reduce iron transport, feedwater iron specifications were reduced by 50% to $\leq$ 10 ppb. In late 1992, feedwater hydrazine 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 instituted in 1992, which concentrated on keeping the sodium to chloride ratio <1.0. The PVNGS specification was adjusted (0.5 - 1.2) to prevent the development of excessive acid conditions in the SG. The above changes were made to address the concerns of high iron transport (crevice formation) and caustic crevice chemistry (excessive sodium).

7. Chemical Source Identification Study

A chemical source identification study was performed to attempt to determine the origin of the impurities located in the SGs. The scope of the study was to identify sources of lead, copper, sulfur, and molybdenum that currently exist or have existed in the Unit 2 secondary system. The threshold of concern for the listed elements considered either a significant percentage of the element in a given component (e.g., 3%), an appreciable wetted surface area (e.g., several square inches), or a single event related intrusion that occurred during 1990 through the present.

The results of the contaminant sources study has determined the probable sources of each element to be the following:

- **Sulfur**
  - 120 cubic feet of resin cannot be formally accounted for. The majority (>99%) of the resin is transported out of the secondary system as backwash water. This level of unaccounted resin is consistent with Units 1 and 3.
  - For every cubic foot of resin, 10 pounds of sulfate is available.
  - Several thousand pounds of secondary piping has eroded. This could have provided the source for several pounds of sulfur.
- **Molybdenum**
  - Some eroded secondary piping contained approximately 1% molybdenum. This would have provided the source for approximately 1 pound of molybdenum.
  - Although other secondary piping and components contain a higher percent of molybdenum, there is no significant evidence of erosion in these lines.

- **Copper**

  - The condenser tube sheet is 88% copper and is 2200 ft^2 in area. Depending on the corrosion rate, approximately five (5) pounds of copper could have been transported from the condenser during the first four cycles of operation. However, the majority of the copper would have been removed by the condensate demineralizers.

- **Lead**

  - The heater drain and condensate pump bearings are made of graphite babbitt which could contain some lead. The bearings may have provided a source of a very small amount of lead.

8. Summary

Unit 2 Steam Generator chemistry has been maintained within plant and industry guidelines. Out of specification conditions were corrected within the time periods specified in EPRI guidelines. Historically, Unit 2 bulk chemistry did not significantly differ from Units 1 and 3. All three units had operated with caustic crevice chemistry and high levels of contaminant return from downpowers. The resin intrusion that occurred in Jan. 1992 contributed to elevated levels of sulfate in the SGs. SG 22 differed from all other SGs in that it had the highest peak sodium return as well as the highest molar ratio calculated via the peak return concentrations. This data indicates that SG 22 has the highest hideout efficiency for sodium and sulfate, and that, in turn, may indicate the existence of the largest concentration of host deposits.

B. Operational Review

A review of operational practices, issues and activities involving the PVNGS steam generators was performed in order to identify any anomalies or areas that would contribute to the potential failure mode identification. From an operating standpoint exclusive of chemistry issues as discussed in the previous section, the following three (3) operating issues were identified: feedwater oscillation, steam generator run time at power, and vibration/loose parts. The results of the Task Force review of these items is summarized below:

1. Feedwater Oscillation

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

The following scenario describes the effect of the positioner failure:

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

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

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

d. Because the main feedwater pumps deliver feed to both steam generators, the change in speed would also vary flow to SG 22, causing the observed level oscillation. In summary, the feedwater control system dominated the SG 22 level control in an effort to maintain SG 21 level. (Note: The described scenario only applies when the main feedwater pump high-select gate in the feedwater control system receives a nominally higher signal from the #1 feedwater control system cabinet. Based on discussion with the responsible engineer, the signal from the #1 cabinet was ~0.4 volts higher than #2.). A summary of the review specific to each Unit 2 steam generator as well as Units 1 and 3 is as follows:

- **Unit 2 - Steam Generator 22**

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

  During blowdown, the magnitude rose to about 2 to 2-1/2% and the frequency dropped to about 20 oscillations per hour. In addition to operator interviews, the team reviewed chart recorder output just prior to the last outage (U2R3, which commenced October 17, 1991) and prior to an unrelated reactor trip that occurred on November 23, 1987. The level of performance of level control was comparable to observations of all three Palo Verde units in the past.

  Based on operator interviews and chart recorder output, slight level oscillations began to emerge in early August, 1992. This included peak-to-peak oscillations of about 4%. These spikes were only detectable until August 6, 1992. On September 7, 1992 the duty Shift Technical Advisor initiated Condition Report/Disposition Request (CRDR) 2-2-0282, identifying the appearance of 5% oscillations. A similar CRDR was written on September 12th (2-2-0287) to

establish a continuing trend. A third CRDR, 2-2-0286, also dated September 12th, noted the same erratic operation during high rate blowdown. The return of the oscillation was also visible on the chart recorder output. The oscillations reached about 5% peak-to-peak. The oscillations lessened in magnitude at approximately 11pm, October 2nd and stopped completely at 3:30 pm on October 4, 1992.

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

After start-up from the 11/13/92 trip, the SG 22 water level was stable again. At the time, occasional oscillations were observed, but at a lower frequency, typically hours apart. On December 8, 1992, however, the frequency returned to earlier levels. The condition persisted, with the oscillations gradually increasing in magnitude and frequency. By the end of February 1993, peak-to-peak oscillations of 8% were common. At the time immediately prior to the tube rupture, SG 22's level oscillations were about 3 to 5% peak-to-peak.

- **Unit 2 - Steam Generator 21**

The team reviewed the Unit 2 steam generator level recorder (2J-SGN-LR-1111) hard-copy output, from July 30, 1992, until the SGTR event date. Level recorder LR-1111 displays the two narrow range SG 21 level transmitters (LT-1111 and LT-1112) that measure steam generator level and input into the Feedwater Control System. The recorder output from July through December, 1992 was "nominal." The trace appeared as an almost solid line approximately 2 to 3% wide. The frequency of these nominal oscillations appeared to be about 40 per hour. During blowdown, the magnitude rose to about 4% and the frequency dropped to about 30 oscillations per hour.

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

- **Unit 1 and 3 Steam Generators**

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

  Modelling of the steam generator thermal-hydraulics was performed to evaluate the possible effects of the level oscillations. The evaluation and conclusions are presented in Section VI.

2. **Cumulative Thermal Generation**

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

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

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

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

3. **Vibration/Loose Parts**

The failure mode investigation included the possible role of vibration and/or loose parts in the cause of the tube failure. This review was performed based on the presence of vibration/loose parts alarms which were received during Cycle 4 in the Unit 2 control room. On some occasions, the alarms were classified as "high-rate" (greater than 4 per shift.) The alarms cleared during abnormal rate blowdowns, however. The Vibration Group identified that the majority of the alarms were on the reactor coolant pumps sensors and not on the steam generators. The PVNGS Vibration Group analyzed the recorded data, including the potential that the signals originated in the steam generator but were detected by the RCP sensors. Based on analysis of the

captured detector signals, the Vibration Group determined that even if the detected signals represented parts or vibration noise from SG 22, they did not originate at the level in the steam generator where the tube rupture occurred. In addition, the alarm rate and times did not have any correlation to the frequency of steam generator level oscillations.

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

It was therefore concluded by the Task Force that loose parts did not play a role in the tube rupture event.

VI. ANALYTICAL STUDIES

A. Thermal Hydraulic Model for Quality/Velocity Distribution

In the early phase of the root cause investigation, the Steam Generator Tube Rupture Task Force observed that the majority of the freespan and eggcrate defects as well as the bridging axial deposits were detected within a defined arc shaped region. Based on this observation, a thermal-hydraulic analysis was performed to determine if a deposit concentrating effect could be confirmed analytically. The Electric Power Research Institute (EPRI) ATHOS II model, using PVNGS specific geometric and process inputs, predicted that the arc region, as empirically defined by the eddy current testing, was in fact a region of high deposition within the System80 steam generator. The following information documents the development of APS's deposit model and provides the results of this analytic effort.

1. Athos II Code Description

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

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

2. Chemical Deposit Parameter

The PVNGS ATHOS model calculated thermal-hydraulic parameters which were used to predict a potential for chemical deposits in the upper tube bundle region of SG 22. An empirical deposit parameter consisting of mass flux (ρV) and a concentration

factor for non-volatile impurities was selected to compare with the ECT measured deposit locations in SG 22. The deposit parameter, combining thermal hydraulic results and non-volatile chemical concentration provided a mechanistic understanding of the most probable location for the observed chemical deposits. Figure VI-a provides the horizontal and vertical nodalization used for the PVNGS steam generator ATHOS II Model.

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

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

3. Analysis of SG Level Oscillation Effects

A review of SG 22 operating data revealed that the steam generator had a history of feedwater flow and the downcomer water level oscillations. The downcomer water level data indicated that the level had fluctuated approximately ± 5 percent of Narrow Range (NR) within a period of one and half minutes. Following the discovery of steam generator tube degradation and deposits, thermal hydraulic analyses were performed to understand the root cause of the observed phenomena and to investigate a possible link between feedwater flow oscillations and tube degradations. The analyses were performed using the ATHOS II code. The operating conditions for PVNGS at 100% power that were used in the analysis are provided in Table VI-1.

The ATHOS output includes a summary of geometric data (See Table VI-3), physical properties of the primary and secondary fluids and tube metal, friction correlation, and numerical parameters used in the computational procedure. The ATHOS output also includes a detailed printout of thermal-hydraulic parameters, line printer plots, and output summary of results. Table VI-2 provides performance characteristics for the steam generator. These include hot and cold side downcomer mass flow rates, total flow and steam mass flow rates at the separator deck, circulation ratio, fluid inventory

and primary inlet and outlet temperatures. (Note: all values are in SI units). Also, all of the flow rates are for one-half of the steam generator. Due to geometric and thermal-hydraulic symmetry only 180° (90° cold and hot sides) of the steam generator were modeled by the ATHOS code.

The result of the analysis was the determination of a "Stability Ratio" for the specific cases described above. The approach to vibrational induced instability is indicated when the "Stability Ratio" is greater than one (1). The details of the analysis are documented in CE Report CR-9417-CSE93-1111 Revision 0. The stability ratio calculated for each of these cases (normal, high, low level) was less than unity. In other words, all cases analyzed were shown to not be experiencing excessive flow instability. It was also demonstrated that there is a negligible impact to fluid velocity, density, or stability ratio values between the normal, low and high SG level cases. Thus, the SG level oscillations described in Section V.B.1 were determined to have essentially no impact to the upper region of the tube bundle.

B. Flow Induced Vibration

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

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

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

The second mechanism results from unsteady momentum flux in the two phase flow regime. The unsteady momentum flux in two-phase flow has been shown to produce

excitation force causing both cross and parallel flow-induced vibrations. According to the experimental study, for a given natural frequency there is a flow regime within which the unsteady momentum flux is very unstable resulting in a large oscillating excitation force. This could contribute to tube damage.

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

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

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

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

Based on the above investigation of the stability criteria for the two mechanisms of flow induced vibration, the steam generator tubes which were susceptible to flow induced vibration were identified for both the in-plane and out-of-plane vibration. Figure VI-n shows two zones that would be susceptible to flow-induced vibration. Zone 1, consisting of the entire rows from Row 106 up to Rows 159, would be susceptible to both

mechanisms of unsteady momentum flux and fluidelastic instability. Zone 2 would be susceptible only to the fluidelastic instability mechanism.

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

Based on the results of the vibration analyses, it is concluded that FIV could potentially be a contributor to the observed axial cracking if it assumed that the 08H and 09H supports are ineffective for certain tubes.

C. Design/Fabrication Review

A review of the fabrication methods employed by Combustion Engineering, as well as a review of engineering and construction records regarding the fabrication of the PVNGS SGs, was performed by the Task Force. The purpose of the review was to determine if a link existed between the initial fabrication and the observed failures. The design history/ evolution of the U-tube support structure was also reviewed.

The review process included discussions with some of the personnel who were involved in the design and fabrication of the Steam Generators. Special emphasis was placed on evaluating the tubing manufacturing process, the tube bending operation and the tubing insertion into the steam generators.

As described in Section IX, the ability of certain tubes to be in close proximity to or come in contact with other tubes is considered to a contributing factor in the root cause of the tube rupture. Therefore, studies on the potential for the tubes to buckle, bow, and ratchet were conducted by APS and Combustion Engineering. Also, a general review of the SG design and fabrication was performed to identify potential contributors to the tube rupture and high rate of tube degradation in the Unit 2 steam generators.The results of this evaluation are presented below:

- **Fabrication**

  The review of the fabrication process for PVNGS's steam generators was performed by CE, and reviewed by the Task Force. No unusual fabrication problems were identified during the Palo Verde Unit 2 fabrication record evaluation. The fabrication facts and conclusions resulting from the review are as follows:

- Tube Bundle Fabrication

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

- Tubing Manufacture

There were no major differences in the manufacturing process for the tubing between Units 1 and 2. All tubing was produced by the pilgering process by the same tube mill (Noranda) and to the same specifications. The only change identified during the evaluation was a change to the ID noise level acceptance criteria. The specified criteria for Unit 1 required that all tubes whose average ECT horizontal indication exceeded 400 millivolts and/or vertical indication exceeded 100 millivolts were rejected, while the criteria for Unit 2 increased the limits to 800 millivolts and 150 millivolts respectively.

- Tube Bending

Unit 1 tubing was furnished bent by the tubing supplier. Unit 2 tubing was furnished straight by the tubing supplier and tube bending was performed in house by Combustion Engineering. The in-house bending process for nuclear steam generators began in late 1977 on units for other utilities. The tubing for Palo Verde Unit 2 was bent in mid-1978. This process required samples to be bent and furnished to CE engineering personnel for evaluation before beginning the production bending. Evaluation of the bending process was performed to the same criteria by Combustion Engineering for all three units. The record search did not reveal any problem with the in-house tube bending process.

- Tubing Operation

Deviations from CE engineering requirements were documented in rejection notices. In addition, logs were kept in the tubing room while the steam generators were being tubed. The purpose of these logs was to identify problem areas and record the tubing progress.

Rejection notices dealt mainly with scratches on tubes and/or nail indentations. All tubes that were identified as having scratches were polished to remove the scratches. All tubes identified as being dented from nails were replaced. No tubes were installed with known scratches and/or indentations. Tubes with rejected conditions due to the tubing process, but could not be removed and replaced, were plugged.

At the end of the log (SG 22) for the 3rd shift on 08/23/78, there was a note that read "2 tubes extremely hard."referring to the tube bundle insertion process. These tubes would have been in row 116 or row 117. This was established based on the notation that 49 tubes were installed in row 116 and 21 tubes were installed in row 117 for that shift. The record search did not provide any additional information that would assist in identifying those two tubes by specific row number and/or line number.

The search of engineering records did not reveal any additional problems over and above those documented in the rejection notices. The shop foreman responsible for the tubing operation was also interviewed as part of this evaluation. He noted that from a steam generator fabrication standpoint, all of the PVNGS units were similar.

- Steam Generator Fabrication Following Tubing

  All steam generators undergo the same basic fabrication steps following the tubing operation. There was no indication that anything unusual occurred in this phase of fabrication for Unit 2 or, specifically, SG 22.

- CE Engineering Records

  There were no significant findings resulting from review of CE's engineering records. There was no indication that the Unit 2 steam generators were designed or fabricated different from the Unit 1 steam generator's.

- **Tube Bowing and Buckling Analysis**

Combustion Engineering performed tube bowing and buckling studies based on indications of reduced tube spacing and tube bowing.The scenarios considered by CE included distortion during initial fabrication, gross binding of the tube bundle at the I-beam supports, vertical binding of individual tubes at the batwings, and lateral binding of individual tubes in the vertical supports. Finite element models were used to analyze the tubes for buckling instability and large deformation bowing. The results of the analytical studies were combined with information obtained from fabrication records research and Unit 2 steam generator inspections to evaluate all of the scenarios hypothesized. The analytical studies are described below:

- Buckling/Instability Studies

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

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

The U-Bend model was analyzed to determine the effect of the U-Bend and the vertical supports on the instability load. The instability load was determined to be 1064 lbs. This showed that the true buckling load is much higher than simple column theory.

Both cases show the instability load to be higher than loads which could be postulated. Analyses show that if there was gross binding by the I-Beams, the axial force on the tube would be only 142 lbs. Fabrication records show no general use of high forces to install the tubes and it is inconceivable that the load would have been over 1064 lbs since this was a "one man" operation per tube leg. Therefore, it can be concluded that buckling instability and resulting closure of the gap would have been improbable.

- Large Deformation Bowing Studies

In similar fashion, even if the loadings were not severe enough to produce tube buckling, deformations may occur that are sufficient to narrow or close the gap between tubes during operation. Large deformation theory, finite element analyses were performed to determine deformations resulting from thermal deformation for vertical loadings.

Finite element models of tube row 117 were used to conduct the analyses. Two basic models were used: a straight tube model and a U-Bend model. These are shown in Figures VI-p and VI-q respectively. The straight tube model represents the tube span between eggcrate 08H and the batwing. The model is actually a half-span model to facilitate boundary conditions, i.e., full support at mid-span and simple support at the batwing. The U-Bend model represents the hot side of the complete tube. The eggcrates and vertical supports are modelled as simple supports with full support at the tubesheet. In both models, eggcrate 09H is

assumed to be inactive since it only supports one side of the tube. Once the potential for buckling was discounted, the U-Bend models were used to investigate the potential for large deformations to close or narrow the gap between tubes.

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

The actual support behavior is difficult to define absolutely. Although the vertical supports were designed to allow lateral motion, it is conceivable that the vertical motion could result in binding that would prevent or restrict sidesway. However, previous inspections show wear at the vertical supports indicating that lateral movement of some amount has been occurring. Thus it is concluded that gross binding of the tube bundle at the I-beams could produce lateral tube deformations of sufficient amount to narrow and, in fact, close the gap between tubes. However, as determined by the SG 22 secondary side inspections conducted during U2R4 and U2R2, there was no evidence that such binding was occurring.

The tubes thermally expand in the vertical direction 0.218" more than the batwing. This condition was also analyzed and evaluated. Total restraint of this deformation produces large axial and bending loads above those required to yield the tube and the batwings. Since the inspection during U2R4 did not reveal this type of structural failure, the possibility of large lateral deformations due to batwing- tube vertical lockup was discounted.

The final scenario that was postulated which could narrow the gap between tubes was thermal ratcheting. The tube bundle experiences more lateral thermal growth than the batwings, therefore, if individual tubes bind at a vertical support or batwing during heatup or cooldown, relative motion could occur between adjacent tubes. The relative lateral motion of tube row 117 and the batwing is 0.032", as a result, the gap could close by this amount during a single cycle and experience ratcheting closure motions of the same magnitude through a slip/stick mechanism during subsequent operational cycles.

- **Analysis of Tube/Support Contact Forces**

Analytical models were developed from design characteristics of the steam generator tube and tube support structures to determine if higher than anticipated tube-tube support contact forces existed in the upper bundle region of the System80 steam generator. A three-dimensional, finite element model of the tube bundle was used, with tube regions lumped together for model simplification. The analysis included the effect of dead weight and thermal loading for several load cases.

The detailed, three-dimensional, finite element studies of the Palo Verde steam generator tube bundle were initiated several years earlier in order to gain an understanding of the causes of tube defect indications found in the upper bundle regions of the Unit 2 steam generator during U2R2 and U2R3. The results, using nominal design values, indicated that thermal and flow contact forces were low and did not indicate a relationship with the tube defect indication pattern found at Palo Verde. However, it was the recommendation of the Task Force to consider hypothetical boundary conditions which might result from the presence of a more aggressive environment. The load cases are summarized below:

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

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

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

- Case B: Tube/Batwing Lock-upThis hypothetical condition was evaluated to see if sufficient reaction forces could develop at tube/batwing intersections which might, in turn, cause some tubes to bow or deflect into adjacent tubes. For the hypothetical case of a tube and batwing completely bonding together (perhaps from corrosion), the analysis showed the batwing would try to restrain vertical growth of the tube and could induce significant reaction forces. Batwing and tube bending stresses (axial direction) could exceed yield. Also, the tube could deflect into adjacent tubes. However, this is a hypothetical condition and current inspection results do not confirm such a boundary condition.

- **Summary of Design/Fabrication Evaluation**

Design changes incorporated into the System80 design by Combustion Engineering to the upper tube bundle support structure were driven by concerns over corrosion, ease in manufacturing, and small localized problems of flow induced vibration. When this evolution is viewed from an analytical perspective, the designs all meet engineering requirements for a support structure in this application. The flow-induced wear problems of CE designed steam generators were the batwing wear phenomenon in the 3410 Series and the corner tube wear problem of the System 80. In both cases, the wear was limited to a small localized area of < 100 tubes, which is < 1% of the tubes in the bundle. Such localized wear had no impact on the accuracy of the analytical model that justifies the overall design. The two cases of flow induced wear also occurred in the outermost row of tubes and could be characterized as "interface problems" with the surrounding structure and were not indicative of conditions in the center of the tube bundle; where tube R117C144 ruptured.

Additional analysis was performed by CE (CENC-1950) in April, 1993 to investigate flow instability in the upper bundle region. This study was a second verification of the loads in the upper bundle and the propensity to wear due to high vibration. Loads were introduced axially on the horizontal tube runs during normal power operation in an attempt to induce vibration. The results showed that the basic design of the upper bundle supports of the System 80 SG was sound. Based on those results, it can be assumed that the overall design of the System 80 steam generator is not subject to flow induced vibration. The analysis did have a caveat however. The analysis assumes that all tubes were free to expand vertically.

D. Wear Analysis

A study of the U2R4 steam generator eddy current examination was conducted to evaluate the presence of tube wear in SG 21, and SG 22. Bobbin coil indications that were identified ECT were characterized by MRPC. Those categorized as wear that were greater than 20 percent throughwall were included in the study. The wear indications in U2R4 were compared with the U2R3 eddy current results. The U2R3 eddy current data was reanalyzed for indications which had changed by greater than 10 percent. Indications which had not yet been reanalyzed were excluded from this study. The study results are presented in Tables VI-4 through VI-7.

Based on the results of the study, the average wear rate SG 21 and SG 22 was determined to be 11 percent and 10 percent, respectively. It should be noted that the wear rates determined by this study were biased high by the exclusion of data from wear indictions of below 20 percent. These wear rates should not be misconstrued as indicative of the overall rate of degradation in the steam generators. However this information was used to

determine SG wear behavior, compare generator wear rates, and as a baseline for future wear/crack correlations.

The average change in wear depth of the tube defects at 09H support was determined to be 22 percent in SG 21, and 18 percent in SG 22. This location had the largest increase in wear indications in both steam generators. The 09H support includes a scallop bar contact point for rows 116, 117, and 118. Tables VI-5. and VI-7 present a breakdown of the wear at the scallop bars. The 09H scallop bar area accounted for over 50 percent of total wear and new wear indications for the 09H support location in both steam generators.

Figure VI-t provides the location of wear indications in each steam generator. As depicted in the figure, the majority of wear in both steam generators has occurred in the 08H, 09H, BW1, and VS3 supports. Figures VI-u provides the location where the majority of new wear occurred in the Unit 2 steam generators. In each steam generator the BW1 support did not have as much new wear as the 09H support despite having a higher percentage of the total wear. Although a large proportion of the total wear in each steam generator occurs at the vertical strap supports, only a small percentage of the new wear indications were found at these locations.

Based on the study results, the two steam generators exhibit consistent wear patterns. The wear rates, 09H scallop bar behavior, and the location of the majority of both previous wear and new wear were consistent in each steam generator. This consistency is particularly evident for the location of new wear sites as illustrated by Figures VI-u. The uniformity of wear pattern indicates that the wear was not caused by support damage or a manufacturing defect. Since it would be expected that, based on a typical Weibull progression analysis, the proportion of new wear would be consistent with the location and quantity of wear indications from previous inspections, the BW1 and VS3 locations should have the greater percentage of new wear indications. Rather, the results indicate that 09H support had the highest wear rates and percentage of new wear which, in turn, provides a possible indication that at least one dynamic phenomenon responsible for this change is occurring in the generators. Further study will be conducted to determine if this phenomenon can be linked to an increase in crack propagation.

E. Deposit (PDP) Study

Based on the ECT and video results, as well as the conclusions of the ATHOS deposit modelling, the Task Force conducted an evaluation of these deposits to determine patterns and extent of the bridging deposit conditions observed in the Unit 2 steam generators. MRPC examinations performed during U2R4 were able to detect the presence of OD deposits using the 20 kHz absolute eddy current channel. The deposits were primarily located between 07H to several inches above the batwing. As of July 2, 1993, a total of677 deposits or PDPs had been classified on 570 tubes in SG 21 (See Figure VI-v) and 464 deposits had been classified on 415tubes in SG 22 (See Figure VI-w). It should be noted

that in many cases the MRPC signal can not discriminate between scale, fouling or hard, tightly adhering deposits. (See photographic examples in Figure VII-Pictures 3,6,and 8).

After tube pulling, video examinations were performed on tubes surrounding the pulled tubes. Deposits were observed to bridge at least 3 pairs of tubes. Orientation testing was performed on 31 tubes using a magnetic index referencing (MIR) probe in a tube adjacent to the target tube. The results of this testing (See Figure VI-bb through jj) found a high degree of correlation between the orientation of the flaws and the deposits. Deposits were identified in 54 of the 102 free span axial cracks in both generators. In addition,50 of the 102 deposit/free span axial correlations were detected at the same height indicating that reduced spacing or bridging may have occurred. MRPC had found 110 pairs on 227 tubes in SG 21 (See Figures VI-x and VI-y) and 65 pairs on 131 tubes in SG 22 (See Figures VI-z and VI-aa). These paired deposits, and the previously noted tubes with single axial deposits, could be assumed to be potential future crack initiation sites, and therefore will be specified for future bobbin and MRPC inspection programs.

The appearance of deposits in the U-Bend region, and to a lesser degree in the horizontal portion, is consistent with the evaluation presented in the deposit formation model. In the ATHOS model, it was determined that the deposits should occur preferentially in areas where steam blanketing occurs. These areas were determined from correlations developed for flow in vertical channels as opposed to a cross flow situation as would occur in the horizontal bundle region. Furthermore, these correlations are known to have uncertainties up to 20%. The inspection results imply that some steam blanketing may extend to the first vertical support. This conclusion is supported by the presence of ECT detected deposits in the region.

VII. STEAM GENERATOR INSPECTION

A. Eddy Current Inspections

1. Eddy Current Testing (ECT) Conditions and Methods at PVNGS

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

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

- **PVNGS Steam Generator ECT Program**

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

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

  - 550 kHz Differential-used for detection and sizing to satisfy PVNGS Technical Specifications and ASME Section XI.
  - 550 kHz Absolute - used for mix component and defect confirmation.
  - 990 kHz Differential and Absolute - used for inside diameter mix component.
  - 100 kHz Differential and Absolute - used for outside diameter mix component and tube support locating.

- 20 kHz Differential and Absolute - used for sludge, loose parts and locating tube supports locating.

- 550-100 kHz Differential - Mix 1, used to suppress tube supports, loose parts, deposits and etc., for detection and sizing.

- 550-100 kHz Absolute - Mix 2, used to suppress tube supports, loose parts, deposits and etc., for sizing of wear at batwings, vertical straps, eggcrates, and the flow distribution plate.

- 550-100 kHz Differential - Mix 3, same as Mix 1 except high span to detect indications at the roll transition.

- 550-990-100 kHz differential - Mix 4, used to suppress geometry changes (IDC, offsets, expansions, etc.) for detection.

- **Standard Eddy Current Techniques at PVNGS**

  - Bobbin Coil

    The bobbin coil (See Figure VII-a) is a widely utilized ID probe with high inspection rates of up to 26 inches per second. The eddy current flow is directed around the tube circumference and is primarily sensitive to volumetric and axially oriented degradation. The probe is sensitive to probe fill factor variations, where fill factor is a measure of the degree to which the ID space is occupied by the bobbin coil probe. As a result, tube ID variations such as tube wall corrugation due to pilgering may affect detection and sizing capability. Typically, PVNGS uses a size 610 (0.610" diameter) bobbin probe for full length bobbin inspections. Smaller probes (i.e. 590 or 540) are used when obstructions from denting, and ovality are encountered.

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

    a. Absolute Mode: Current flow in the tube parallels the coils windings, and is preferred for detection of gradual discontinuities such as wear or tube thinning

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

- Motorized Rotating Pancake Coil (MRPC)

  The MRPC probe (See Figure VII-b) is a small surface riding probe which is rotated and translated through the tube at a much slower inspection rate of 0.2 inches per second. It is estimated that to perform a full length MRPC inspection of one tube would be approximately 1.5 hours; or greater than 600 days to inspect a System80 steam generator. PVNGS utilizes a standard three-coil MRPC which consists of an axial, circumferential and pancake (both directions) probe. The probe surface riding capability reduces lift-off as an extraneous test variable and is therefore less sensitive to tube ID variations.

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

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

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

  - BWNS Electronic Rotating Field Eddy Current Probe (RFECT)

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

additional testing may demonstrate equivalent capabilities for future inspections.

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

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

- Flexible MRPC U-Bend Probes

  Prior to U2R4, a three coil MRPC of the square bend and horizontal region of the System80 steam generators could not be performed due to the rigidity of the MRPC probe and motor driver assembly. As a result of concerns regarding the performance of bobbin coil due to tube curvature and ovality, Zetec developed a flexible three-coil rotating pancake coil probe. The rotating section is a maximum of eight feet in length as the motor driver remains in the vertical section of the tube.

- Magnetic Indexing Referencing (MIR) Probe

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

- Video Inspection

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

- 630 Bobbin Coil Probe

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

- Mid-Frequency Bobbin Coil Probe

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

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

- Ultrasonic Testing (UT) Probe

  The use of UT was considered by APS to verifying bobbin coil and MRPC detectability threshold. However, based on discussions with CE and BWNS, the use of UT was not regarded to be an inspection improvement in terms of detectability and/or inspection production rates. At Arkansas Nuclear One, Unit 2 (ANO-2), ultrasonic shear wave testing was conducted to assess the nature and severity of circumferential and axial OD cracking. The testing was performed by NUSON Inc. - a recognized industry leader in this field. UT failed to detect the presence of axial indications found with ECT techniques. Additionally, the UT consistently undersized the average depth of the ANO-2

tubesheet indications. Furthermore, a review of UT production rates found that inspection speeds for UT were 2-5 times slower than MRPC, without a corresponding gain in detectability.

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

- **Bobbin Coil Re-evaluation**

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

a. Provide training to analysts on defect characterization.

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

c. Zoom the CRT Strip Chart to enhance the display in the area of interest.

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

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

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

Using this methodology, the number of defects not identified by the bobbin coil (NBI) would be reduced. Typically, the reevaluation would report these locations as non-quantifiable indications (NQI) which by procedure requires inspection by MRPC, and would therefore provide a detectability level equivalent to MRPC limits. APS intends to incorporate these techniques in a revision to PVNGS Station Manual Procedure 73TI-9RC01 and future ECT analysts training.

2. Eddy Current Inspection Results

The daily progress of the evolving eddy current testing in the Unit 2 steam generators was followed closely by the Task Force. The exams included 100% Bobbin Coil eddy current and extensive Motorized Rotating Pancake Coil (MRPC) examinations of both

SG 21 and SG 22. The original scope of Eddy Current Testing (ECT) planned for the U2R4 outage was a 100% Bobbin Coil inspection and a 10% random MRPC inspection of the tube sheet and flow distribution plate. This original inspection was planned so as to locate axial cracking at the tube sheet and the 01H flow distribution plate; axial cracking in freespan locations; wear at the cold leg corners, batwings, and vertical straps; and loose parts.

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

Due to the number of defects found during the ECT during the U2R4 outage, 14 MRPC expansions were made to the original ECT scope in SG 21 and five (5) expansions in SG 22. A summary of the types of MRPC sampling performed in U2R4 and the basis for inspection is provided below:

- **Justification for MRPC Sample Plan**

  There were two objectives of the U2R4 MRPC program. The first was to perform a thorough inspection of the area of the steam generator in which a disproportionate number of axial indications had been detected. That area of the steam generator corresponds to an area that thermal-hydraulic analysis predicts has a higher propensity for solids and contaminant deposition as described in Section VI.A. The second objective was to perform sufficient MRPC inspections outside the area of interest to demonstrate that probability of defects below bobbin coil detection outside the area of interest would be acceptable and would not represent a challenge to the safe operation of the facility.

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

  a. Definition of Arc Segment Area Of Interest

     An area of the steam generator containing a disproportionate number of axial indications exists in the upper bundle of the steam generator near the outer periphery of the tube bundle (Figures VII-c and VII-d). As described in Section VI, thermal-hydraulic analysis results indicated there was a higher propensity for deposition in an area near the outer periphery of the tube bundle extending

from the tube bend on the hot leg side down to approximately the 07H horizontal eggcrate support (Figures VI-c thru VI-m).

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

Using 0.7 as a general guide for defining the MRPC program, an MRPC inspection pattern was developed (see Figure VII-e) with the objective of conservatively bounding the axial indications observed and provide an inspection of the area identified by the thermal-hydraulic analysis. Approximately 3800 tubes comprised the arc segment and were MRPC inspected, as a minimum, from the first VS support down to 08H including the tube bend. As indicated in Figures VII-f and -g, all upper bundle axial indications, whether in the free spans or at a support, were contained within the inspected region. The actual inspection pattern is slightly different in each steam generator in order to provide a five (5) tube buffer sone around any indications near the edge of the inspection area.

b. MRPC Inspections Beyond Arc Segment

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

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

Additional MRPC inspection of tubes surrounding this indication was performed and no additional indications were identified.

Tubes in a checkerboard pattern, groups of tubes located radially inward from the arc, and groups of tube segments of tubes within the arc but below (inspected below 08H) the defined area of interest were randomly selected and inspected. Table VII-1 and 2: provides an accounting of the number of tubes inspected and the vertical extent of the inspections. The location of the tubes inspected outside the arc below BW1, tubes inspected in the hot leg bend outside the arc, and those within the arc inspected below 08H is illustrated in Figures VII- h through j. No axial indications were detected during the random inspections. Using the guidance provide in the PVNGS Technical Specifications, at least 3% of the tubes outside the arc in SG 22 have been inspected from 08H to BW1 and from BW1 to the first VS support.

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

c. 07H to 08H Free Span and 07H Inspections

The vertical extent of the area of interest was originally considered to be from BW1 to 08H. Subsequent thermal hydraulic analysis results confirmed the highest propensity for deposition was from BW1 to 08H. However it was decided that inspections be performed down to 07H (roughly corresponding to a deposit parameter of 0.7). This inspection scope would provide greater assurance that the vertical extent of the area of interest had been bounded. Approximately 1065 tubes in SG 21 and 489 tubes in SG 22 out of the 3800 tubes contained within the arc have been inspected down to at least the 07H support and an additional 1999 tubes in SG 21 and 3300 tubes in SG 22 were inspected at the 07H (i.e. were inspected continuously from BW1 to 08H and then also at 07H) using MRPC. No additional axial indications were found by MRPC below the 08H support.

d. Statistical Analysis

A statistical analysis was performed based on the Unit 2 steam generator MRPC and bobbin coil inspection programs to estimate the number of axial indications, not detected by bobbin coil outside the arc, that might be detected by additional MRPC (See Section XIV - Appendices). A traditional statistical approach was used in which the area of disproportionate bobbin indications would be treated as a high risk area and areas not exhibiting unusual numbers of bobbin indications would be treated as low risk. This analysis concluded that there was a high confidence level (95%) that there would be a limited

number of axial indications (7 or less total and 6 or less free span defects) outside the arc which would be identified by MRPC inspection. For comparison purposes, the EPRI-recommended 20% random sample (EPRI NP-6201), which is an accepted method for establishing sampling scope, allows the utility to suspend sampling if 90% confidence of fewer than 12 defects is achieved. Accounting for some analysis uncertainties, the results would still indicate that additional sampling outside the defined arc segment is not required.

- **Defects Found During Unit 2 Inspections**

  The ECT results to date (7-6-93) indicate that the SG's had experienced axial cracking at the following locations:

  - support cracks at the 01H support and the tubesheet (See Figures VII-l1 and l2)
  - support cracks from the 05H to the 09H support
  - free span cracks in the tube sections between the two highest partial eggcrates
  - support cracking at the batwings
  - free span cracking between the batwing support and the vertical tangent to the U-bend (Figure VII-k1)
  - free span cracking at the horizontal tangent to the U-bend (Figure VII-k2)
  - support cracking at the Vertical Straps

  A summary of the entire inspection program is best displayed via tubesheet maps included as Figures VII-c through VII-l and tabulated results given in Tables VII-1 thru 6.

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

B. Eddy Current Detectability

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

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

1. Industry Experience

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

As reported in EPRI document NP-7480-L the morphology of intergranular corrosion explains the reduced eddy current response for small cracks. The observed field degradation, multiple short cracks coupled with an intergranular nature of the cracks, allows paths for the eddy currents to pass uninterrupted through the degradation. An appreciation for why this phenomenon occurs comes from the use of liquid metal modeling techniques. Using this technique, degradation is simulated as inserts in the liquid metal, and degradation morphologies that are difficult or impossible to machine (EDM notches) can be easily simulated. The difference in "real" cracks and notches have been modeled by varying the contact between the faces of the crack.This work showed that interfacial contact of 50% could reduce eddy current response by a factor of five (5). This same factor was identified by Dr. C.V. Dodd of the Oak Ridge National Laboratory in a June 8,1993 letter from the NRC to APS. In Dr. Dodd's report the estimated detection levels for bobbin coil and MRPC were 70% and 50%,

respectively, for crack-like defects at PVNGS. However, it is APS's position that a definitive correlation can not be drawn from the liquid metal testing, due to the inability of quantifying the level of ligament bridging or interfacial contact of the PVNGS defects. The actual PVNGS tube examination results provide a better baseline for comparison with industry data.

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

2. PVNGS Tube Pull Laboratory Results

From the inventory of eight (8) tubes sections removed from SG 22, six (6) areas with axial cracking were selected to be burst tested in the laboratory. After burst testing, crack profiles were generated for each crack location to allow direct comparison with eddy current results. Table VII-7 provides a compilation of actual measured crack depths/lengths, corresponding field bobbin, field MRPC indications, measured burst pressure, and calculated burst pressures based on actual measured average crack depth and length. Cracks that were detected by field bobbin are indicated by non-quantifiable or distorted signals NQI, DSI, or by numerical entry in the "Field Bobbin" column. An NBI entry in this column indicates the crack was not detected by bobbin coil inspection. Cracks detected by MRPC are indicated by a SAI or MAI (single or multiple axial indication) in the MRPC column. An NDD entry indicates the crack was not detected.

From the data presented in Table VII-7 (referenced above), Figure VII-m provides a graphic illustration of the percent of cracks detected by both bobbin and MRPC for ranges of actual crack sizes from the population of cracks found on the pulled tubes. The information provided detectability comparisons between bobbin and MRPC for axial crack indications based on average through wall depth. As shown, the eddy current detectability threshold for 100% detection, based on average crack depth, is

50% through wall for bobbin and 40% through-wall for MRPC. Those detectability thresholds are consistent with current industry guidelines.

Figure VII-n provides a similar detectability determination, based on maximum crack depth. To determine which comparison is appropriate for use as a detectability threshold, a comparison of the actual burst pressures versus the predicted burst pressures, based on average and maximum crack depths, is provided in Table VII-7 and illustrated in Figure VII-o. The comparison demonstrated that a correlation between actual and predicted burst pressures can be achieved using the average crack size. Thus, the average crack size is more indicative of the structural integrity of the tube than the maximum crack size. Therefore, 50% average through-wall depth will be used as the bobbin coil detectability threshold. Similarly, 40% through-wall will be used as the MRPC detectability threshold. The detectability thresholds are utilized in the Regulatory Guide 1.121 evaluation as described in Section X.

- **Noise Level Effects**

  - Description of PVNGS System80 Steam Generator Tubing

    The tubing material installed in the PVNGS System 80 steam generators is a high temperature mill annealed (HTMA) Alloy 600. The tubing for Units 1 and 2 was manufactured by Noranda and Unit 3 tubing was supplied by Sandvik. The tube extrusion was accomplished utilizing a pilgering process. With the exception of the Palisades replacement steam generators, no other Combustion Engineering generators use pilgered tubing. The Millstone 2 replacement steam generators were manufactured by B&W Canada with pilgered Inconel 690 tubing. Tubing manufactured for pre-System80 plants was cold worked via a bench drawing process.

    Both cold drawing and pilgering operations are depicted in Figure VII-p. Although most Combustion Engineering, Westinghouse and Babcock and Wilcox original steam generators have been supplied with drawn tubing, most recent replacement steam generators were ordered with pilgered tubing. The choice between pilgering and drawing involves both technical and economic considerations for the utility. For example, the amount of wall thickness reduction per pass during extrusion is typically high for pilgering, and low for drawing, and therefore pilgered tubing can be manufactured quickly and economically. Alternatively, inservice inspectability is decreased for pilgered tubing due to internal (ID) surface corrugation which results from the pilgering process. Pilgered tubing typically has eddy current noise levels two to four times that of drawn tubing (See Table VII-8, Figure VII-q). It should be emphasized that ID irregularities from the pilgering process do not cause or indicate defective tubing, but requires that measures be taken by the purchaser

in specifying manufacturing limits for signal-to-noise ratios, or in the utility inservice inspection programs to account for the impact of pilger noise on inspectability.

- Signal to Noise Ratios:

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

  - Mask small amplitude eddy current signals resulting in non-detection of tube wall degradation.
  - Require a decrease in the SG tube plugging limit if excessive sizing error is required to support Reg Guide 1.121 design basis.
  - Permit repairable defects to remain inservice due to incorrect sizing of small amplitude indications.

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

  APS has reviewed eddy current data for all three units in an attempt to determine an average S/N ratio for each PVNGS steam generator. The methodology used in this comparison was similar to the approach presented by EPRI in EPRI Report NP-6750-SD. The signal source was a 0.052 inch diameter ASME hole standard, and was compared to the noise generated as a

result of ID and wall thickness variations. The signal-to-noise ratio is the ratio of the peak-to-peak signals of the ASME hole and of the ID noise as shown in the lissajous patterns using the primary frequency of 550 kHz. The results are presented below in Table VII-9:

TABLE VII-9

SG #	ASME Standard (volts)	Noise (volts)	S/N Ratio
1-1	6	0.84	7.1
1-2	6	0.54	11.1
2-1	6	2.1	2.9
2-2	6	2.1	2.9
3-1	6	0.80	7.5
3-2	6	0.62	9.7

These values can be compared with the summary of drawn and pilgered tubing examined by EPRI (See Table VII-8). As shown in Table VII-9, the Unit 2 steam generators have S/N ratios that are below the EPRI and Laborelec recommended minimum values. Since the tabulated values are averages, an indeterminate number of tubes in the Unit 2 generators exist with S/N less than 2.9:1. Therefore, minimizing tube noise effects is important for the pilgered tubing installed in the Unit 2 steam generators.

- PVNGS Eddy Current (ECT) Program:

Improvements in eddy current technology have provided analysts with the tools necessary to reduce the effects of pilgering noise. Screening for defects at PVNGS is accomplished by using a frequency mix (P1 550-100 kHz) to eliminate the effects of support plates, and permit evaluation of signals present in the vertical plane. Pilgering noise is effectively managed at PVNGS by adjusting the detection/screening display such that the noise signals are in the horizontal plane (See Figure VII-r). The ASME standard and tubing flaws and degradation are displayed in vertical presentations (See Figures VII-s thru u). It should be noted, that while horizontal noise in Unit 2 is nearly five (5) times that of drawn tubing, in most cases the vertical noise is approximately the same magnitude as values as given for drawn tubing.

The low S/N ratios observed in the Unit 2 steam generators are below the levels recommended by EPRI, Laborelec and Valinox for reliable defect measurement. However, the S/N values are adequate for defect detection. Since all tubing with suspected cracks are verified by MRPC and removed

from service, crack sizing is not considered a requirement, and therefore cracks are typically classified with three letter codes such as SAI and MAI. The MRPC probe surface riding capability reduces lift-off as an extraneous test variable, and is therefore less affected by ID surface variations.

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

- Presenting pilgering noise horizontally and screening defects using a vertical presentation. Vertical noise is not considered abnormally high at PVNGS.
- Confirming crack screening with MRPC to eliminate impact of tube noise.
- Not using voltage amplitude threshold criteria or attempting to size axial indications with the bobbin coil screening for determination of repairable defects.

During the U2R4 inspection approximately 22,000 tubes were inspected full length with bobbin coil ECT. A extensive quantity of support intersections and feet of freespan locations were also inspected with MRPC. The MRPC inspection detected a number of indications which were classified by APS as NBI. The NBI designation was assigned to eddy current indications which would not "normally" be reported by the primary and secondary analysts given the training and guidelines provided at the beginning of the U2R4 inspections. However, upon re-review of bobbin signals, with support of the MRPC for location, a small discontinuity in the signal could be detected for a number of these tubes. An evaluation of several locations was conducted to determine if pilgering noise could be "masking" defects. In Tables VII-10 and 11., a summary of noise levels and defect signal strength in tubes with confirmed axial indications were identified. The average horizontal and vertical noise amplitudes in SG 21 were 1.59 and 0.13 volts respectively. Similarly, in SG 22 the noise strength was 1.74 volts horizontal and 0.13 volts vertical.

Voltage signals associated with NBI, NQI and bobbin detected defects were identified, and a signal to noise ratio was calculated. Additionally, ASME standard S/N ratios as high as 17:1, well in excess of the EPRI detectability recommendations, were calculated for some of the affected tubes adjacent to the NBI indication. Therefore, it has been concluded that the defect orientation and characterization is the principle cause of the detectability problems associated with these flaws and not the presence of high pilgering noise.

The pilgering noise in the Unit 2 steam generators is higher than industry recommendations. However, the tube noise is not considered to be a significant defect detectability issue. APS repairs all crack defects regardless of size, and therefore the S/

N ratios recommended by EPRI for defect sizing with bobbin coil techniques do not apply. These conclusions have been discussed and concurred with by industry consultants from EPRI and CONAM.

C. Video Examinations

Following the removal of the tube pull candidates, a secondary side video inspection was performed of the surrounding tubes. A video record was made by moving a remote camera through the full length of the channel created by the pulled tube. To ensure that areas of special interest received a detailed inspection, a check list was prepared as shown on Table VII-12. The objective of this inspection was to evaluate potential tube OD conditions such as flaws and deposits, as well as any abnormal tube bundle physical configurations. Evidence of reduced tube spacing and tube bowing was observed (See Figure VII, pictures 1 thru 8 from Video Inspection) for tubes remaining in the generator as well as the tubes removed via the tube pull operation.

1. Bridging/Ridge Deposits

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

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

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

- **R117C40 and R115C40 (See Figure VII Pictures 1 and 2)**

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

- **R117C42 and R115C42 (See Figure VII Pictures 3 and 4)**

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

- **R103C156 and R102C155**

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

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

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

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

- **R104C157 bridged to R105C156 (pulled) (See Figure VII Pictures 5 and 6)**

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

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

2. **Tube Separation After Whip Cut**

A video inspection was performed, after the whip cut in the tube pulling process, to verify a complete 360 degree tube separation. This inspection was performed by moving a remote camera from the primary side to the elevation of the cut. The video

data from each whip cut was reanalyzed to determine if tube ends after cutting were misaligned. This type of misalignment may indicate a side loading on the tube.

A review was performed of video tapes made during the tube pull whip cut confirmation in which a remote camera was inserted from the primary side tube end to the elevation of the whip cut. Two different camera lens configurations were used. Three (3) tubes were inspected using a straight lens in which the bottom section of a cut tube could be seen in conjunction with the upper section in the background. One tube, R22C13, did not appear to have an offset, but tubes R103C156 and R117C144 appeared to have an offset between the cut tube ends.

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

3. Flow Distribution Plate (01H)

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

D. Secondary Side Inspection

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

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

b. Compare the over-all condition of the upper bundle with the condition observed during a similar inspection two operating cycles previously (U2R2).

The two individuals performing the inspection, one from APS and one from Combustion Engineering, had participated in the previous inspection of the same steam generator. This allowed a direct comparison to be made between the two inspections. The inspection resulted in the following observations:

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

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

3. With one possible exception, clearance between the wrapper bar and the inside of the shroud was clearly visible along the entire length of the wrapper bar. The space between wrapper bar and the shroud was not clearly discernible close to the 270° position of the vessel. Due to the rapid tube bundle slope, which made access to the wrapper bar in the area extremely difficult, the visibility of the wrapper bar was difficult. Space existed between the wrapper bar and the shroud in the area of the ruptured tube (R117C144). In order to detect if the batwings had moved, eddy current data was also reviewed. Tables VII-13 and 14 compare a selected set of batwing heights as measured by ECT in SG 22 with expected design positions. The tables also compares the linearity of the batwings. Within the ability of the ECT to accurately measure height, the results support the visual inspection, in that there is no indication of any significant shift, tilt, or distortion of the batwing supports.

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

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

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

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

VIII. TUBE EXAMINATION RESULTS

A. Examination Process and Scope

Tube pulls were required to support metallurgical examinations and determination of the cause of failure of tube R117C144. The scope of metallurgical examinations intended for steam generator tube failure analysis was developed by APS Nuclear Engineering and the Inservice Inspection group utilizing the guidance provided in Electric Power Research Institute (EPRI) report NP-6743-L, Appendix C. The purpose of the examinations was to determine:

a. tube degradation mechanisms

b. compare field ECT data to actual defect depth using destructive examination techniques, and

c. tube integrity testing via laboratory burst testing of selected tube sections.

From a list of degraded tubes in SG 22, a selection process (Table VIII-1) was applied to maximize the information to be obtained from the tube pull candidates. Tubes selected for removal and laboratory examination fell into four categories:

1. Tubes with flaws at 01H

2. Tubes with mid-span flaws

3. Tubes with flaws at upper bundle supports

4. "Clean" tube

On certain tubes, bobbin inspection did not record an indication but an axial defect was identified with the MRPC. To evaluate that discrepancy, two tubes were selected which met that condition. Also, tubes were evaluated based on their position relative to other tubes with axial indications, including axial deposits. In addition, tubes were chosen to represent different regions of the tube bundle. As a contingency, extra tubes were selected as backup candidates. Table VIII-1 lists the primary and secondary tube pull candidates and the basis for selection. Figure VIII-a shows the areas of the tube sheet where tube sections were removed. A brief summary of the basis for selection is provided below:

1. **Tubes with Flaws at 01H: (R22C13 & R29C24)**

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

2. **Tubes with Mid-span Flaws**

   - Ruptured tube and large through wall flaw (R117C144 & R105C156)

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

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

     Two tubes were selected which contained mid-span axial indications detected by MRPC but not detected by bobbin coil eddy current inspection.

3. **Tubes with Flaws at Upper Bundle Supports (R127C140)**

   In addition to the recorded axial indications at mid-span, some axial indications were found at upper bundle supports. One tube was selected for removal to evaluate this type of degradation.

4. **Clean Tube (R116C41)**

   In order to evaluate the detectability limits of eddy current, one tube which had no indications was selected. An additional criteria for this tube was that it had been located next to tube(s) with recorded flaws.

The tube examinations were conducted at two different laboratory facilities, CE in Windsor, CT and at B&W in Lynchburg, VA.

Once the Palo Verde tube sections were received by the laboratories, the investigation process required daily planning sessions between APS Metallurgical Engineers and vendor Project Managers. When required, the APS Steam Generator Tube Rupture Task Force was consulted to determine if more specific tube information was required to support the total scope of investigations. Therefore, communication among all parties was an integral key to the examination process.

The division of responsibility for the pulled tubes intended for analysis included the following:

- **Tubes Examined at Combustion Engineering**

  R117C144 - Lower section of ruptured tube

  R105C156 - Free span axial defect detected by bobbin/MRPC ECT

  R103C156 - Free span axial defect detected by MRPC but not bobbin

  R127C140 - 07H and 08H eggcrate support axial defects

- **Tubes Examined at Babcock and Wilcox**

  R117C40 - Free span axial defect detected by MRPC but not bobbin

  R116C41 - Tube with no detectable defects for ECT validation

  R22C13 - Tube with 01H tube support plate axial defect

  R29C24 - Tube with 01H tube support plate axial defect

Diagrams of the tubes and the locations of the tube cuts are provided in Figures VIII-b.1 through 8.

B. Nondestructive & Destructive Testing

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

- Receipt inspections
- Visual inspection
- Eddy current testing (both bobbin and MRPC)
- Double-wall radiography
- Dimensional measurements
- Deposit analysis

Following the nondestructive work, destructive testing was performed on the tube defect areas to measure the remaining structural integrity of the defect areas for future analysis, characterize burst fracture faces and wear locations, determine the mode of cracking and

analyze the crack oxide film chemistry to determine the local crevice chemistry environment.

Destructive testing included the following:

- Burst testing
- Light optical microscopy of tube cross sections
- Scanning electron microscopy (SEM)
- Auger electron spectroscopy (AES)
- X-Ray photoelectron spectroscopy (XPS)

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

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

- **NonDestructive Testing Results**

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

- **Burst Test Results**

  Burst testing of axial crack defects was performed at both the CE and B&W facilities. The test results are discussed in a later section of this report as part of the Regulatory Guide 1.121 discussion. In general, tube R105C156 exhibited a burst opening length of 1.38 inches and a burst pressure of 3200 psig (Figure VIII-f). This tube showed a

crack profile of nearly 98 percent throughwall cracking and was considered to be the most degraded tube examined, with the exception of the ruptured tube R117C144. Tube R103C156, also a tube with a free span axial defect, burst at 6968 psig with a burst length of 1.0 inches. The remaining tube burst data are covered in Section X of this report. Figures VIII-g and h show laboratory burst surfaces for tubes R127C140 and R103C156, respectively.

- **Fractography Results**

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

- **Light Optical Microscopy Results**

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

- **Deposit Investigation Results**

  Long axial free span cracks were found under free span ridge deposits that formed as a result of reduced tube clearance and from the propensity of deposits to collect at crevices in the upper part of the tube bundle. Free span ridge deposits were determined to be as thick as four mils on the tube OD surfaces. Normal scale deposits were found to be on the order of two (2) mils thick. Deposit chemical analysis showed a trend for increased concentration of normal deposit constituents and contaminants as the tube bundle height increased. Deposit analysis showed the presence of the following chemical elements/compounds: Fe_3O_4, Cu, NiO, SiO_2, CaO, MgO, ZnO, MnO_2, Al_2O_3, PbO, sulfur species and other minor compounds. Based on a review of deposit data, it was concluded that concentration of these deposits and contaminants could facilitate IGA and IGSCC of Palo Verde's steam generator Alloy 600 tubing.

- **Oxide Film Analysis Results**

  Microanalytical analysis of tube surface and crack surface films using AES and XPS concluded that the crack environment was alkaline (mild caustic) with the presence of sulfates. This was based on the evidence that showed chromium depletion at the crack

tips, which would only occur in an alkaline environment. The presence of sulfates and reduced sulfur on the crack surfaces was noted and was concluded to contribute to the degree of IGA and IGSCC in the alkaline-to-caustic environment. The evidence of some areas showing nickel depletion supports this conclusion as reduced sulfur would precipitate nickel into solution. The crack surface analysis did not indicate a strong caustic or acidic influence to the attack.

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

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

- **Surface Examination Results**

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

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

associated with the tube installation process were found under normal tube scale and the resultant IGA attack was minor, approximately six mils deep in the worst areas.

- **Microstructure Examination Results**

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

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

Microstructural characterization of tubes R105C156 and R103C156 showed an improved microstructure compared to R117C144. However, microstructures of both tubes was less than what is recognized as optimum today. Both microstructures showed the presence of intragranular and intergranular carbides and prior carbide grain boundaries. This indicates that the annealing heat treatment was not a full solution anneal which would have dissolved all carbides, promoted grain growth and provided an inventory of carbon for grain boundary precipitation during cooldown. This results in a lower material resistance to intergranular cracking in the caustic environment for the same reasons stated above. Microstructure evaluation of tubes R127C140, R117C40, R116C41, R22C13 and R29C24 showed acceptable tube microstructures.

- **Wear Examination Results**

Wear indications were also examined in the lab by visual inspection, cross-sectional metallography and SEM. The most significant wear was noted in tube R127C140, which exhibited wear to a depth of 61% at the 08H support location. An example of the wear examination results is illustrated in Figure VIII -s. This wear indication is from R116C41, located at the upper 09H support/scallop bar location. The wear appearance was peened and showed evidence of being an active wear location. Depth of wear was measured to be approximately 25 percent. The cause of wear is believed to be due to sliding/impact wear. Other wear locations were examined on tubes R103C156 (06H) (Figure VIII -t) and R117C144 (07H) support locations. These wear scars were more shallow in depth and had a thin layer of deposits on the tube surface indicating that the wear was not recent. Intergranular attack, both shallow and deep,

was noted to be associated with the wear at these locations. This is due to the surface cold working and the crevice environment at the eggcrate supports. Burst testing of the wear and associated IGA located in tube R117C144 07H support revealed leaking at 8000 psig indicating significant structural strength remaining in these areas.

- **Eddy Current Validation Results**

  Sections of tubing on R105C156 and R103C156 at the 06H and 05H eggcrate support locations respectively as well as nearby mid-span sections, and the entire tube surface on tube R116C41 were found to have had no detectable defects by field eddy current testing. These sections were subsequently examined in the lab to verify that there was no detectable IGA/IGSCC degradation on the tube. These sections were hydraulically swelled to open any surface defects that might have been present, descaled and then liquid penetrant examined.

  The results showed only minor IGA with one isolated area on tube R116C41 that had IGA/IGSCC believed to be approximately 27 percent throughwall at the 09H support location. The test results confirmed that the tube sections examined for ECT verification did not have degradation that was above field ECT thresholds.

- **Material Testing Results**

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

C. Summary of Tube Examinations

In summary, tube R117C144 ruptured due to IGA/IGSCC attack in an alkaline-to-caustic with sulfate environment associated with free span deposits. The detection of cold working due to scratched areas associated with long defects on tube R105C156 suggests that a cold worked surface area was present which when combined with the free span crevice deposits, led to preferred IGA and subsequent early crack initiation.

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

Free span tube degradation found in tubes R105C156 and R103C156 is concluded to be consistent with the damage mechanism found on tube R117C144. The crevice environment was concluded to be alkaline-to-caustic with sulfate formed under free span

crevice deposits. These tubes also had marginal microstructures but not to the degree of the ruptured tube. Of these two tubes, tube R105C156 was the most severely degraded.

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

IX. ROOT CAUSE OF FAILURE

As discussed in Section IV, the APS Steam Generator Tube Rupture Task Force, assembled a flow chart of possible failure modes to develop action plans for ECT, tube pull selection, engineering analysis and laboratory techniques. Using the information obtained from these activities, the Task Force developed a worksheet to identify the most probable causal factors for degradation of the affected tubes. The evidence indicates that the rupture of tube R117C144 was due to IGA/IGSCC which occurred as a result of tube-to-tube crevice formation. The crevice, together with the consequential heat flux, led to an aggressive environment under a ridge deposit. As a consequence, a long deep crack initiated under the ridge deposit, leading to the loss of structural integrity under normal operating conditions. Several additional contributing factors such as: increased sulfate levels due to resin intrusion, likelihood of cold working due to surface scratches, a less than standard microstructure in R117C144, and increased susceptibility of contaminant concentration in the upper region of the tube bundle were also identified by the Task Force.

Therefore, the investigation concluded that the key elements of the tube rupture in the PVNGS steam generator were: caustic-sulfate environment, crevice formation, and residual and applied stresses. Other OD initiated axial defects were recorded at both supports and free span elevations. The damage mechanism for these tubes involves an IGA/IGSCC synergism similar to that of the ruptured tube (See Figure IX-d). The basis for this conclusion is as follows.

A. Caustic-Sulfate Environment

Secondary water chemistry evaluations and pulled tube laboratory analysis indicated the presence of a mildly caustic environment for PVNGS steam generator crevices. This evidence is supported historically by the presence of OD initiated cracks during both U2R3 and U2R4 at support locations, MULTEQ hideout return data reporting crevice pH values of 8.6-10.7 since early 1991 and molar ratios (sodium/chloride) greater than two (2). Microanalytical analysis of tube surface and crack surface films, of the tubes removed from SG 22, using AES and XPS concluded that the crack environment was alkaline (mild caustic) with the presence of sulfates. This was based on the evidence that showed chromium depletion at the crack tips, which would only occur in an alkaline environment.

The elemental analysis detected environmental impurities such as sulfate, sulfide, sodium, lead and copper. None of the impurities found were at levels sufficient to indicate an acute introduction of these species into the steam generator secondary environment. Crack oxide analysis however, indicated sulfate levels in excess of expected values. Published laboratory results indicate that sulfate and reduced sulfides in the presence of a caustic environment can increase the rate of IGA attack of Alloy 600 tube material.Therefore the

presence of sulfates and reduced sulfur on the crack surfaces was concluded to contribute to the degree of IGA and IGSCC in the alkaline-to-caustic environment.

Significant industry data has indicated that caustic induced IGA/IGSCC Alloy 600 tube degradation has been a common phenomena in steam generator tube crevice locations. However, this form of degradation is typically manifested at tube support and tubesheet crevice locations and not at free span locations such as those observed at PVNGS. The presence of IGA/IGSCC at free span locations is a function of tube-to-tube crevices occurring at locations where the nominal tube spacing had been reduced.

OD initiated cracks at the flow distribution plate, eggcrate supports and free span crevices could therefore be expected based on the chemistry and laboratory results. However, since the majority of defects were detected within a defined arc-shaped region, a thermal-hydraulic analysis was performed to determine if a concentrating effect could be confirmed analytically. The APS ATHOS II model predicted that the arc-shaped region, as empirically defined by the eddy current testing, was a region of high deposition within the System80 steam generators. The deposit parameter, combined thermal hydraulic results with a quality-related, non-volatile chemical concentration to provide a mechanistic understanding of the most probable location for the observed chemical deposits. Additional conducive factors identified by the Task Force, such as previously high corrosion product transport levels, and lengthy continuous 100% power run times, could exacerbate crevice conditions.

B. Crevice Formation

While IGA/IGSCC, in caustic environments, is a well understood condition for tube support and tubesheet crevices, the formation of free span crevices appears to be a new phenomena. Physical evidence from video inspections performed in the space left by tube section removal, confirmed the presence of bridging deposits in locations where the normal tube triangular pitch spacing is reduced to nearly tube-to-tube contact (See Figure VII Picture 3). Evidence of tube bowing or bending was found in sections of tubes removed from the 08H-09H regions (See Figure VIII-C.1 and C.6). Additionally, a number of ECT-detected linear deposits occurred in tube pairs (See Figures VI-y and VI-aa). While these observations indicate that reduced tube spacing is occurring within the higher elevations of the tube bundle, a quantitative determination of the number of affected tubes was not feasible with the technologies available. Similarly, a definitive reason for these observations could not be found during this investigation. However, based on the generator design, some qualitative reasons could explain the presence of free span crevices.

The tube "bowing" or reduced tube spacing appears predominantly in the upper region of the bundle, in longer unsupported tube sections (See Figure IX-b). It is unlikely that similar tube space reductions could occur in the vertical sections contained within

multiple eggcrates. The Task Force investigated both design and fabrication information to determine if a significant feature could lead to tube-to-tube contact in either the cold or hot condition. The design of the upper bundle supports (i.e. Batwing and Vertical Straps) does not prevent possible lateral or in-plane tube movement which could create reduced tube-to-tube spacing (See Figure IX-a). Such movement, especially in relatively long unsupported tubes (See Figure IX-b), could result from original bundle fabrication, restricted thermal expansion or a higher than design dead weight loading on the horizontal tube sections from the vertical supports. Either one or a combination of these factors could result in a less than nominal gap between adjacent tubes.

The relative scatter within the arc region of defects (See Figures VII-c and VII-d) and deposit indications (See Figures VI-y and VI-aa) could also be attributed to a fabrication variation in the tube manufacturing or bending process. Since a majority of paired deposits appear to be column oriented, a bowed condition along the extrados of the bend tangent could be theorized.

The video examinations conducted during the tube pull operation further supports the extent and randomness of this condition. With respect to deposits, the video examination in the tube lanes of the pulled tubes identified three (3) examples of close tube-to-tube proximity, with a thicker axial deposit buildup bridging the area where the tubes were closer together (See Figure VII Picture 3). Similarly, two other tubes displayed a distinct, thicker axial deposit buildup where the tube had been in proximity with the removed tube. Each of the four (4) flawed full length tubes pulled from the steam generator included visual evidence of near-contact and resultant bridging deposits. The video also confirmed the presence of a deposit and bridging over five (5) additional flaws on tubes which were not pulled. The bridging deposits had not only a general composition of iron oxide, similar to typical scale or fouling particulates, but also had higher than normal chemical contaminant concentrations. There was no evidence that bridging deposits could develop in areas of normal tube spacing. The bridging deposit acted as a "host" for the chemical contaminants, which increased in concentration due to steam blanketing in the higher levels of the tube bundle as described in the deposit parameter model. Under examination in the laboratory, the most severe IGA and IGSCC was observed under the bridging deposits.

Based on the video and laboratory results, the Task Force attempted to further support the correlation of deposits to defects using ECT techniques. The video results were compared to the results of eddy current testing with the MRPC. The eddy current analysis identified the presence of a deposit on six out of eight of the bridging deposits viewed on the video. The classification of deposits was largely judgmental by the eddy current analysts, thus smaller signals may not be classified, explaining the fact that not all visual observations were classified.

As of July 10, 1993, axial deposits were identified over 54 of the 102 mid-span axial cracks (12 of 16 in SG 21, 42 of 86 in SG 22). In addition, deposits were detected at the same height of an immediately adjacent tube in 50 of the mid-span cracks (nine (9) in SG 21, 41 in SG 22,) which was considered to be evidence that reduced spacing and deposit bridging had occurred at those cracks. Based on the comparable results of eddy current testing to the video observations, additional examples of adjacent deposits (without flaws) were located. These tube locations were also assumed to be closer together with bridging deposits. Based on a review of the ECT data, 110 sets of deposits (227 tubes) were identified in SG 21 and 65 sets (131 tubes) in SG 22. These 358 tubes are assumed to be potential future crack initiation sites and therefore will be monitored in future ECT inspection programs. Additional locations may exist, since experience has demonstrated that some deposits are not classified, as discussed above.

Forty-eight (48) of the mid-span axial cracks did not include indications of deposits. Thirty-two (32) of the cracks without indicated deposits were located in the area immediately above the batwing where the vertical tube begins to enter the radius, as depicted in Figure IX-c. Although undetected over the flaws, 334 examples of deposits were noted in the same area, including 73 pairs of adjacent tubes. The lack of indication may be due to deposit detectability as the tubes begin to move away from each other.

C. Applied and Residual Stresses

The applied hoop stress, due to the normal operation differential pressure, is sufficient to lead to axial crack initiation in the presence of a corrosive caustic crevice environment. In the case of some of the pulled tubes, long free span scratch indications were observed in some locations as possible crack initiation sites. These scratched areas resulted in a cold worked surface layer of material which could increase the tube's susceptibility to stress corrosion cracking. Additionally, short range residual tensile stresses can also aid the crack initiation process. (e.g., high residual tensile stresses as a result of mechanical damage were confirmed to be the root cause of the McGuire Station tube failure).

The Task Force considered several factors regarding the presence of mechanical damage on the PVNGS steam generator tubes. Scratches or damage from tube bundle fabrication has been observed within the industry. Therefore, damage such as observed in the laboratory analysis of the removed sections could have resulted during either the bending process or tube installation. As with tube "bowing" the quantity of tubes involved is indeterminate. It should also be noted however, that not all scratches or grooves result in areas of high residual tensile stresses.

Although cold work resulting from fabrication induced scratches is considered to be a likely factor for initiation of a critical length crack, there are other potential factors which could also generate areas of cold work in the same longitudinal mode that were considered by the Task Force. Two possible factors are flow-induced vibration and/or the tube bowing

itself. Both factors were postulated based on some tube examination evidence of impact wear. Additionally, flow induced vibration may also produce a high cycle/low amplitude applied Hertzian contact stress which could act as a crack accelerator for existing tube degradation.

Continued evaluation of the flow conditions in the Unit 2 steam generators (with flow oscillation) and future inspection results of the Unit 1 and 3 steam generator tubes (which are historically free of excessive tube wear) may help determine the exact role of these two factors in contributing to the initiation and propagation of the crack in the ruptured tube.

D. Conclusion

The evidence indicates that the rupture of tube R117C144 was due to IGA/IGSCC which occurred as a result of tube-to-tube crevice formation. The crevice, together with the consequential heat flux, led to an aggressive environment under a ridge deposit. As a consequence, a long deep crack initiated under the ridge deposit, leading to the loss of structural integrity under normal operating conditions. Several additional contributing factors such as: increased sulfate levels due to resin intrusion, likelihood of cold working due to surface scratches, less than standard microstructure in R117C144, and increased susceptibility of contaminant concentration in the upper region of the tube bundle were also identified by the Task Force.

X. REGULATORY GUIDE 1.121 EVALUATION

NRC Regulatory Guide 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, based on the projected crack growth rate, to ensure that the safety margins specified by the Regulatory Guide are not violated during the next operating cycle. The evaluation is performed by first determining a reasonable crack growth rate based on eddy current results between the last two inspections and compared with industry experience and laboratory data. Next, a structural evaluation is performed to determine the maximum allowable crack size to meet the specified safety margins. This determination defines the allowable end of cycle (EOC) condition.Finally an initial, beginning of cycle (BOC) crack size is selected based on the eddy current detectability threshold, as determined in Section VII.B.2. From these three factors the operating time to reach the allowable EOC condition can be determined.

A. Crack Growth Rate Analysis

Crack growth rate analyses, as applied to return to power issues of tube integrity and safety margins, were based on information obtained from several areas. Current and previous NDE records were used to track the history of tube degradation and establish crack growth rates. Pulled tube examination results identified the operative degradation modes and the metallurgical condition of the tubes of interest. Chemical conditions leading to the observed degradation were estimated from plant chemistry data, bulk corrosion product chemical analysis and the characterization of the composition versus depth profiles of surface films. With an evaluation of the environmental and metallurgical conditions leading to the observed degradation, expected crack growth rates from plant specific NDE data were compared to the historical performance of other plants with similar conditions and laboratory test data. With these comparisons in place, a reasonably conservative crack growth rate was selected for use in structural integrity evaluations.

Examinations of pulled tubes from Palo Verde Unit 2 located a combination of IGA/ IGSCC on the outer diameter of tubes in four types of hot leg crevices:

- 01H drilled hole baffle plate crevices
- Eggcrate crevices in the upper part of the bundle
- Tube-to batwing contact crevices
- Crevices created by long linear deposits on tubes near mid-span locations above the 08H supports.

The depth of degradation, as characterized by bobbin coil eddy current testing, was very similar at these locations. The cumulative frequency of occurrence is plotted versus bobbin coil depth in Figure X-a for cracking at the 08H level and above. A median rank approach with the Benard equation was used to estimate the cumulative distribution probability. The distribution of crack depths at the current inspection is essentially the same at eggcrate/batwing and mid-span crevices. The degradation mode at all crevice locations is IGA/IGSCC. However, this phenomena is more prevalent in the upper part of the tube bundle. As noted in Section VI.A of this report, thermal hydraulic conditions promote the transport and deposition of solute species to the upper part of the bundle and favor concentration at higher elevations. The average bobbin indication depth for indications below the 08H level is about 0.67 times the average bobbin call depth at 08H and above. Hence crack growth rates in the lower part of the bundle are expected to be about two-thirds of the growth rates in the upper part of the bundle.

The previous bobbin coil inspection (1991) revealed indications in 01H crevices and three mid-span locations, which indicated that IGA/IGSCC developed over more than one cycle of operation. Analysis of eddy current records for precursor signals for tubes which currently exhibit crack-like indications did not produce much information. Precursor signals could not be distinguished from the vertical background noise. Hence assumptions must be made concerning the extent of degradation at the beginning of Cycle 4. Previous indications at the end of Cycle3 point to an ongoing process with an orderly progression rate.

A reasonable approach to estimating crack growth rates is to assume a distribution of crack depths at the beginning of the last cycle. This distribution of depths should range from zero to some maximum value. The lower limit of zero is supported by previous indications of degradation. The maximum value must be the smaller of the 50% depth detection limit or the actual bobbin depth call. With any symmetric distribution, the most likely beginning of cycle crack depth for a given indication is one half of the above range. Hence, the beginning of cycle crack depth is selected as either 25% for indications called as greater than 50% thru-wall or one half of the reported depth of indications called as less than 50% thru-wall. Using this latter approach, the cumulative distribution of crack growth rates is plotted in Figure X-b. As noted above, no substantial difference was noted as a function of crevice type in the upper part of the bundle.

Ninety five percent of the growth rates were less than 2 mils/month. Pulled tube results, laboratory data and the performance of other units were used to examine the reasonableness of this crack growth rate value in the following sections. As a point of reference, selection of a zero beginning of crack depth, would only change the largest crack growth rates by about 20%. In the lower part of the bundle below 07H, the appropriate crack growth rate is considered to be two-thirds of the 2 mils/month value; or 1.4 mils/month.

As previously noted, consideration of all factors indicated an alkaline/caustic crevice environment leading to caustic induced IGA/IGSCC. Surface damage at some locations is believed to have contributed to the initiation of degradation via the presence of local cold working and short range residual stresses.

General plant operating experience indicates that propagation rates for IGA/IGSCC degradation in crevice regions proceeds at a relatively slow pace. For example, application of interim plugging criteria for ODSCC at drilled hole tube support locations support full cycle operation with implied growth rates of less than about 1 mil/month. Plant historical NDE records typically allow tracing of indications to precursor signals in NDE records of previous cycles. It is recognized that midcycle outages have been required for occurrences of crevice region IGA/IGSCC in the past. This would imply conservative growth rate estimates in the vicinity of 1 to 2 mils/month.

Degradation of Alloy 600 tubing in caustic environments has been extensively studied and most of the IGA/IGSCC, which has been observed in steam generator tube crevices, is considered to be caustic related. Laboratory testing combines both crack initiation and crack growth. Results in many cases must be considered carefully in order to extract the pertinent crack growth rate data. Metallurgical conditions must also be considered. Some tests with good characterization of the loading stress intensity factors involve plate rather than tubing with a corresponding variation in metallurgical condition. Metallographic examination of pulled tubes at Combustion Engineering revealed microstructures in tubes R117C144, R105C156 and R103C156 considered to be less than normal expectations with increased susceptibility to IGA/IGSCC. Figure X-c shows a plot of IGSCC crack growth rates observed in elevated temperature 10% NaOH solutions as a function of reciprocal absolute temperature. With respect to applicability, pressurized capsule data from two different sources is considered most relevant. The capsules were actual steam generator tubing. The hoop stresses were only a factor of two higher than the normal differential pressure hoop stress. Many laboratory tests were at yield point levels and beyond. The range of estimated Palo Verde Unit 2 crack growth rates were also plotted. The range of data agreed with the caustic laboratory data.

Other data in the literature relative to caustic environments is plotted in Figures X-d and X-e, as taken from NUREG/CR-5117. Comparison of these figures indicates that propagation rates for IGA are about an order of magnitude slower than IGSCC. There is substantial spread in the data. In the case of IGSCC growth rates, most of the test data is at stress levels very much higher than the differential pressure hoop stress of 9.9 ksi in a tube at normal operating conditions. Even with this substantial conservatism, the maximum growth rate at 300°C, the temperature of interest, is 0.13 μm/hr. which is 3.7 mils/month. Comparison of a growth rate of 2 mils/month based on analysis of plant specific NDE data with industry experience and a very broad range of laboratory data indicates 2 mils/month to be a reasonable, conservative choice for structural integrity evaluations.

The applied hoop stress due to normal operation differential pressure is sufficient to lead to crack initiation in the presence of an aggressive caustic-crevice environment. In the case of the pulled tubes with long free span indications, scratches were observed as preferential crack initiation sites. These scratches created a cold worked surface layer of material with increased susceptibility to SCC. Additionally short range residual tensile stresses are also expected to aid the crack initiation process.

The growth rates of IGA/IGSCC corrosion degradation appear to be nearly the same for all crevice types, 01H, support location crevices and free span bridging deposits. While surface damage is viewed as facilitating crack initiation, crack growth rates have not been affected to the extent that is statistically significant. One clear effect of scratches under some bridging deposits is the length of cracking as detected by the MRPC eddy current probes. Figure X-f shows a plot of cumulative probability of occurrence versus crack length as found by MRPC. The eggcrate/batwing crevice and free span distributions are nearly the same. About 95% of all indications are less than one inch in length for the eggcrate/batwing crevices. This value increases to about 1.4 inches for the free span indications if the outliers are not included. These outliers are believed to be due to the coincidence of bridged deposits (free span crevices) and scratches. Two tubes with long free span indications which fall outside the general population have been pulled and examined. Long scratches under the bridged deposit facilitated crack initiation over long lengths leading to long deep flaws. A long, near uniform depth flaw is required for burst before leak at normal operating conditions. At a differential pressure of 1180 psi, the required through wall crack length for bursting is about 1.8 inches. Hence the crack depth of burst tube 117-144 had to be nearly through wall over the full observed 2.0 inch burst length. Review of Figure X-f indicates that this is more likely in the presence of a scratch which develops simultaneous initiation over a long length.

It can therefore be argued that the structurally significant part of a long indication is no longer than the length detected by MRPC. The burst tube had (from the burst appearance) a structurally significant length of about 2.0 inches. Long cracks are considered to have been created through the presence of scratches as favored initiation sites. The worst case for a structurally significant crack length has been observed to be 2.0 inches. The reported MRPC length after the burst event was approximately nine (9) inches. The length of degradation which determined the actual burst strength was much smaller. Future long cracks are expected to be less severe. A reasonably conservative approach would be to select the expected worst case length for the next run period equal to the next worst case length from the burst crack. This would be approximately 1.4 inches and would be consistent with previous analyses of the burst strength of tubes with scratches or gouges as crack initiation sites. In terms of allowable end of cycle depth of degradation, the selection of 1.4 inches or the burst tubes' structurally significant length of 2 inches is a relatively small effect. However the argument that the next most worst case is less than 1.8 inches is basically an argument that leak before break conditions must be met for normal operating differential pressure. This is believed to be the case.

B. Structural Evaluation

The tube integrity with postulated axial flaws on the outside diameter was evaluated to the requirements of RG 1.121. These requirements are designed to maintain specific margins for service degraded steam generator tubing against potential rupture during plant operation. Separate margins are specified for normal operating conditions and postulated accident conditions.

The recommendations of RG 1.121 specify that tubes with part through-wall cracks should have a safety factor against failure by bursting under normal conditions of not less than 3. Margins against tube failure under postulated accidents should be consistent with the margin of safety given by the stress limits specified in NB-3225 of ASME Section III. Analysis margins for Service Level D loads under NB-3225 and Appendix F of ASME Section III indicate a stress allowable of 0.7 S_u can be applied for faulted loads.

Therefore, the tube integrity analysis for part through-wall axial flaws will satisfy RG 1.121 if the following safety factors on burst are met:

SF = 3.0 (normal operation)
SF = 1.4 (accident)

Because the flaw orientation is axial, the principal stress affecting tube integrity will be the hoop stress. Under normal operating conditions, the tube hoop stress will be diminished by pressure loading only and will be a function of primary and secondary side pressures under steady state conditions. For postulated accident conditions, the limiting transient is the condition that creates the highest hoop stress in tubes. For faulted loads, such as LOCA and MSLB, hoop stress under MSLB will be the limiting condition due to the loss in secondary pressure. Therefore, MSLB was chosen as the bounding condition for this analysis. Peak RCS pressure as provided by the pressurizer at the start of a large steam line break during full power operation with concurrent loss of offsite power is 2,400 psia. This pressure is a maximized initial condition of the UFSAR Chapter 15 MSLB accident analysis. Although this pressure attenuates rapidly with time, a conservative condition for tube integrity is to assume an instantaneous loss in secondary pressure to pure vacuum condition inside the generator. There is no subsequent repressurization of the RCS to above the specified initial condition following the MSLB. This is because the PVNGS High Pressure Safety Injection (HPSI) pumps have a shut-off head of approximately 1875 psia, well below the normal RCS operating pressure. Since there is no repressurization of the RCS, it would be overly conservative and inappropriate to use the primary safety valve setpoint to determine the peak RCS pressure for the MSLB event.

Therefore, the hoop stress will be bounded by the following tube pressure loadings:

	Normal Operating	Accident (MSLB)
Primary (psia)	2250	2400
Secondary (psia)	1070	0

The burst condition for a tube with a part-through axial flaw was determined from a net-section plastic collapse formula proposed by FRAMATOME in EPRI NP-6865-L:

$$\sigma = \left[1 - \frac{\ell \frac{a}{t}}{1 + 2t}\right] \frac{\sigma_f}{SF}$$

where,

σ = Hoop stress

σ_f = Flow stress = 0.577 ($\sigma y + \sigma u$)

l = Flaw length

a = Flaw depth

t = Tube wall thickness

SF = Safety factor

The above equation has been verified against laboratory tube tests involving EDM slots, simulated SCC defects, V-notches, simulated IGA defects, and burst tests on pulled tubes. Figure X-g presents a graphical correlation of calculated burst pressure as a function of measured burst pressure. Excellent correlation between the calculated and measured burst pressure is demonstrated. An argument could be made that other correlations available in the industry literature would provide a more conservative prediction of burst pressure. However, a comparison between calculated and measured burst pressures for the pulled tubes from Palo Verde Unit 2, using the Framatone equation, indicates (as shown previously in Figure VII-o) this correlation provides a conservative prediction of burst pressure for all the tested cracks except for the R127C140 crack at the 07H support. This crack was a short, essentially through wall crack. The Framatone and other correlations do not predict the burst pressure well for near or through wall cracks. A better correlation for this crack can be obtained by determining the average depth over only the near through wall portion of the crack. The resultant improved correlation is illustrated in Figure VII-o (Referenced previously) for the R127C140 -07H data point. However, based on the over-

all conservative prediction of the pulled tube samples, it is APS's position that the use of this correlation is sufficiently conservative for use in this Regulatory Guide 1.121 evaluation.

The limiting flow stress for the tube material was established by statistical analysis (See Figure X-n) of the reported yield and ultimate strengths provided in the certified material test reports. A 95% probability of occurrence, at a 95% confidence level was used as the criterion for determining the statistically-based bound on yield plus ultimate strength for the tubing in each generator.

Using the above described burst correlation, the maximum allowable crack depth as a function of crack length is determined as illustrated in Figure X-h. This figure provides the allowable crack size for the limiting Reg. Guide 1.121 case. For the PVNGS steam generators, the MSLB times 1.4 safety factor is more limiting than the 3 times normal operation. The figure also illustrates the actual limiting accident case (MSLB with no safety factor) and the normal operation case.

The determination of a maximum allowable crack depth requires consideration of crack length. The most conservative approach would be to consider an infinitely long crack. The limiting RG 1.121 curve in Figure X-h asymptotically approaches 65% depth with increasing crack length. Therefore, 65% would be the most conservative alowable crack depth. A more reasonable approach, however, would be to consider the structurally significant part of a long crack. The ruptured tube had a burst length of about 2.0 inches and can be considered to be the worst case. Future long cracks are expected to be less severe. As discussed in Section X.A., a reasonable expected worst case length for the next run period would be equal to the next worse case length from the current inspection, or approximately 1.4 inches long. Using 1.4 inches as an expected limiting crack length for the next operating period then yields a maximum allowable crack depth of 68%.

C. Initial Crack Size

Having determined an expected crack growth rate and allowable end-of-cycle (EOC) maximum crack size to meet Reg. Guide 1.121 safety factors, a determination must be made of the expected beginning-of-cycle (BOC) condition of the steam generator tubes. This determination is made based on consideration of ECT detectability threshold. As discussed in Section VII.B.1, industry experience indicates a reasonable bobbin coil detectability threshold of 50%, which had been used previously in Reg. Guide 1.121 submittals. Industry experience also indicates a 40% detectability threshold for MRPC. As illustrated previously in Figure VII-m, the results of the Unit 2 pulled tube exams agree well with the industry experience with respect to ECT detectability. Therefore, for the purpose of this evaluation, tubes within the concentrated MRPC inspected area will be assumed to have a limiting BOC crack depth of 40%. Tubes outside the concentrated

MRPC-inspected area will be assumed to have a limiting BOC crack depth of 50%, based on bobbin coil detectability.

D. Determination of Next Operating Cycle Length

Figures X-i and X-j graphically illustrate the determination of the operating length such that Reg. Guide 1.121 safety factors are maintained. Figure X-i is for those tubes within the concentrated MRPC-inspected area. For this case, an initial crack depth of just below the 40% MRPC detectability threshold is assumed, and a crack growth rate of 2 mils/ month is applied. As indicated, the Reg. Guide 1.121 limit of 68% is reached in approximately 6 month.

Similarly, Figure X-j is for tubes not within the concentrated MPRC-inspected area. For this case, an initial crack depth of just below the bobbin coil detectability threshold of 50% is assumed and a crack growth rate of 1.4 mils/month applied. The Reg. Guide limit is again reached in approximately 6 months.

Based on this evaluation, the next operating cycle for PVNGS Unit 2 until the next steam generator inspection will not exceed 6 months of power operation.

E. Statistical Evaluation

A statistical evaluation (FPI Proprietary Report FPI-93-427) was performed to support the deterministic evaluation described in the preceding sections and to provide an alternate method to examine the appropriateness of the assumptions used in the deterministic evaluation. The statistical evaluation is based on determining a beginning of cycle crack distribution derived from probability of detection and the measured (by bobbin coil) crack distribution from the current Cycle 4 inspection. To this a crack growth rate distribution, determined from the difference between Cycle 3 and Cycle 4 data, is applied; resulting in an end of cycle crack distribution. From this end of cycle crack distribution, it can be demonstrated, with 95% confidence, that there is a 95% probability that the Regulatory Guide 1.121 limits will not be exceeded. Sensitivity studies using industry POD and a more conservative end of cycle allowable crack depth are also performed.

- **Determination of Crack Growth Rate and Crack Propagation Time**

  Figure X-k illustrates crack growth rate from a statistical view point. The crack growth rate is determined from the bobbin probe measurements conducted during the Cycle 3 and Cycle 4 refueling outages. In Cycle 3, there were only three bobbin indications. In Cycle 4, there were 58 bobbin indications, but only 34 had measured depth calls. From these two groups of measurement data, the mean crack depth (% through wall) and standard deviation is determined to be 5.8% and 20% for Cycle 3 and 61% and 24%

for Cycle 4. Note that all three tubes with measured crack indications in Cycle 3 were removed from service, resulting in no measured cracks at the beginning of Cycle 4. However, for the purpose of calculating the crack growth rate, it is assumed that there is a 5% chance that the bobbin signature was mis-read, resulting in 5% of the measured tubes being left in service with defects at BOC 4.

From the difference between the measured crack distribution at BOC 4 and EOC 4, the mean crack growth rate is determined to be 2.8 mils/month (6.27%/month) with a standard deviation of 0.884% as illustrated in Figure X-l.

- **Maximum Operation Time**

  To obtain a 95% probability with 95% confidence that Reg. Guide 1.121 limits (68% depth as determined in Section X.D) are not exceeded at the time of the next inspection, an allowable true EOC crack distribution can be derived as illustrated in Figure X-m. From this, an allowable measured crack distribution using the POD curve is obtained. The allowable operating time then is determined as the difference between the EOC measured crack distribution and the BOC measured crack distribution after all the cracked tubes are plugged. The measured BOC distribution assumes 1% of tubes with defects. In this manner, the allowable operating time is determined to be 13.2 months.

- **Sensitivity Analysis**

  To determine the sensitivity of this result to assumed probability of bobbin signature being mis-read and end of cycle allowable crack depth, a worst case evaluation was performed. This analysis used a 5% chance of bobbin coil signature being mis-read, an allowable end of cycle crack depth of 62%, and a desired 99/99 probability/confidence level. Using the same methodology as described above, the allowable EOC condition is reached in 10.8 months. The sensitivity of the result to an assumed normal true distribution was evaluated using an exponential distribution. The study results in a similar operation time.

Based on the statistical evaluation described above, the mean crack growth rate is 2.8 mils/month. This value is very close to the deterministic result of 2.0 mils/month. The difference is mainly a result of different assumptions made in these two types of analyses. The deterministic analysis assumes that the initial crack size after the Cycle 3 outage is non-zero. The statistical analysis, based on the measured data, assumes they are essentially zero. Even though the statistical analysis derives a slightly higher growth rate than that from a deterministic analysis, the final result of the deterministic analysis in allowable operation time is less than that from the statistical analysis.

It is concluded that the proposed 6 months of power operation is conservative. There is high degree of confidence that Unit 2 can be operated for this length of time without

exceeding the safety factors specified in Regulatory Guide 1.121. Maintaining the required safety factors specified in Regulatory Guide 1.121 ensures that operation of Unit 2, with this operative steam generator tube degradation mechanism, does not introduce an unresolved safety question. Assumptions and inputs used in the deterministic evaluation such as ECT thresholds, the Framatone burst correlation, and estimated crack growth rates are considered to be reasonable and appropriate based on the level of agreement with the results of the statistical evaluation.

XI. STEAM GENERATOR RECOVERY PLAN

Corrective actions to address the IGA/IGSCC and its effect on steam generator integrity and plant operability are grouped into various categories and discussed below. These include actions to be taken prior to restart, those to be implemented during operation, and long term actions, as well as improvements in leak detection monitoring and operator response.

A. Actions Taken Prior to Restart

- Condensate demineralizer (CD) inspection

  Since the presence of sulfate from resin intrusions is considered a factor in the steam generator tube degradation observed in Unit 2, all seven CD vessels were inspected during U2R4 and repaired as necessary to ensure resin retention elements are in good working order. The following is a summary of the repairs completed prior to restart:

  a. Service Vessel A - Five failed retention elements repaired/replaced, resin trap replaced.
  b. Service Vessel F - Two failed retention elements repaired/replaced, resin trap replaced.
  c. Service Vessel C - Liner and concrete damage repaired.
  d. Service Vessel E - Resin Trap strainer replaced.

- Steam Generator (SG) drain and fill

  After completion of the tube pull operations and tubesheet plugging, the steam generators were placed in a wet layup condition (pH of 9.5, nitrogen overpressure > 5 psig and hydrazine > 100 ppm). While in this layup condition, sulfate continued to be solubilized from the deposits, increasing to greater than 50 ppb (well within the EPRI specifications). To minimize contaminant loading in the SG and the secondary system, the SG's were drained and refilled with condensate storage tank water (CST).

- Steam Generator Plugging and Staking

  PVNGS Technical Specifications Section 4.4.4.4.a.6 requires steam generator tubes to be removed from service if a defect exists which is greater than 40% of the nominal tube wall thickness. APS Nuclear Engineering has developed a conservative plugging criteria based on defect type and Regulatory Guide 1.121 limits. Currently the PVNGS Engineering Plugging Criteria applied for U2R4 is as follows:

- Tubes with wear indications ≥ 20% for Stay Cylinder Batwing and Cold Leg Corner wear.
- Tubes with wear indications ≥35% for all other support locations previously examined with no wear detected, or if the tube had not been ECT inspected in the previous outage.
- Tubes with wear indications from 39% ≥x ≥35% for locations that had previous indications ≥ 20% need not be plugged.
- All PLPs with any detectable wear
- All suspected cracks
- All SVI indications whose bobbin coil examinations have shown a change in any of the last three ECT inspections

Tube stabilization requirements are specified in N001-6.03-440, Steam Generator Tube Stabilizer Staking Report/Guidelines for PVNGS. Typically tubes are stabilized for stay cylinder batwing wear, cold leg corner wear and PLP locations. The removal of tube sections in SG 22 resulted in a unique configuration which required additional analysis to assure that the remaining sections of tubes did not pose a concern to active tubes in the steam generator. The tube pull contractor, BWNS, utilized its standard 2-D Flow Induced Vibration (FIV) code to qualify the stabilized condition. This was accomplished by first performing an analysis of the original tube and support configuration to determine its fluid-elastic stability margin and maximum turbulence response. An analysis was then performed for the cut and stabilized tube and the resulting stability margin and turbulence response was determined relative to the original condition. If the cut and stabilized tube stability was equivalent or better than the original condition, this was considered to be an acceptable stabilization of the tube. APS Nuclear Engineering and ABB-Combustion Engineering independently verified the tube stabilization methodology.

The remaining tube ends for the pulled tubes at Palo Verde Unit 2 SG 22 fall into three categories. They are:

- Tube cut above 08H or 09H and the tube end is not fully restrained horizontally.
- Tube cut below 09H and the tube end is fully restrained horizontally.
- Tube is cut below 03H and the tube end is fully restrained horizontally.

Tubes which were not cut below a captured horizontal support (Case 1) have been analyzed and determined to be effectively stabilized by a 0.5 inch diameter stainless steel cable extending from the cold leg side tubesheet to the tube cut end. The cable was attached to the cold side tubesheet plug. As an additional conservative measure, adjacent tubes will be plugged and stabilized in a containment pattern around the pulled tube.

Tubes which were cut below a horizontal support (Case 2) result in a tube end fully restrained in the horizontal direction. These tubes were effectively stabilized by a 0.5 inch diameter stainless steel cable extending from the cold leg side tubesheet to the tube cut end. The cable was attached to the cold side tubesheet plug. The analysis performed for the Case 1 tubes enveloped the tubes in this category.

Tubes cut low (Case 3) did not require stabilization. The tube response above 08H was not significantly influenced by the tube end conditions at 03H.

B. Operational Corrective Actions

Palo Verde Site Chemistry formalized a plan in December 1992, to reduce the potential for steam generator related power generation losses and to extend steam generator life. The scope of this plan was to address the concern of IGA/IGSCC, primarily due to caustic bulk water conditions and iron transport (crevice formation). The relationship of all the secondary chemistry control objectives is referred to as "min/max chemistry" (See Figure XI-a). The operational objectives are to minimize contaminant level input into the steam generator, maximize the return or removal of contaminants from the SG and to mitigate the corrosive environment in the SG. With the exception of boric acid and planned periodic downpowers, the majority of these objectives have already been implemented in Units 1 or 3. Preliminary indications of those control objectives that are measurable, demonstrate relative success. Unit 1 has maintained the molar ratio (ratio of sodium to chloride) less than one. The control of this parameter is a leading indication of the neutralization of the SG crevice environment. During a recent shutdown in Unit 1, the hideout return chemistry (MULTEQ) analysis (lagging indicator) was substantially less caustic (near neutral) than what had been measured previously.

The SG root cause of failure for the U-2 Steam Generator Tube Rupture (SGTR) event identified the bulk secondary chemistry environment of the SG as a contributory factor. However, not all secondary system corrective actions can be implemented prior to restart or during initial startup. Some operational corrective actions are dependent on stabilizing the unit after startup. The corrective actions have to be consistent with concerns of a contaminated secondary system cleanup and water processing. Planned operational corrective actions to address the alkaline environment and deposit formation during Cycle 5 are as follows:

- Molar Ratio Control

  The most difficult control parameter is the ratio balance of cations to anions in the crevices to prevent the formation of caustic or acidic environments. Molar ratio control has been best achieved in PVNGS Units 1 and 3 by partial or full condensate demineralizer (CD) bypass, and a continuous CD system performance improvement program. Once Unit 2 is stabilized after restart, CD operation will be manipulated to control the molar ratio within approved operating specifications.

- Minimize Source Term Input

  Contaminant source term inputs to the steam generators will be minimized, dependent on plant conditions. Contaminants have been shown to concentrate in SG crevices and tube deposits. Source term studies at PVNGS have indicated that the condensate demineralizers have been the primary source of sodium. Chronic leakage of sulfate from regenerate chemicals and resin fines were determined to be the source of sulfate ingress. The CD performance improvement program will be implemented during Cycle 5. Additionally, a resin monitoring program will be implemented to identify if a resin intrusion event has occurred, and to alert plant staff to a potential maintenance issue.

- Reduce Iron Transport

  Iron transport to the SGs is the primary makeup source of deposits. The bridging and support deposits, known to have contributed to the IGA/IGSCC, are comprised primarily of iron oxides. Iron transport will be minimized and maintained within new, lower plant operating specifications. Currently, Units 1 and 3 utilize elevated pH to control corrosion product transport. Unit 1 has recently converted to Ethanolamine (ETA) for pH control while Unit 3 continues to inject ammonia as its pH additive. Unit 2 will not start up on ETA (because of radwaste water processing concerns), but ETA will be slip streamed in once stable conditions have been achieved. Dependent on plant conditions, pH will be optimized, in Unit 2, by either ETA or ammonia addition to reduce iron transport. The pH will be increased and the condensate demins will be removed from service as necessary.

- Elevated Hydrazine

  A corrosive environment can be mitigated by operating secondary chemistry with elevated hydrazine. Feedwater hydrazine levels will be maintained according to plant operating procedure specifications during Cycle 5. The elevated hydrazine level (>100 ppb) will ensure that a reduced electrochemical potential environment exists, thereby increasing resistance to IGA/IGSCC.

- Blowdown Optimization

  PVNGS intends to maximize SG blowdown efficiency during Cycle 5 operation. Blowdown is the only means to remove contaminants from the steam generator. The blowdown schedule will be optimized, using normal, abnormal and high rate blowdown, to control SG contaminant levels and maintain proper molar ratio control. Blowdown optimization will be a specific task undertaken by the Steam Generator Working Group.

- Maximize Hideout Return via Periodic Downpowers.

  Downpowers have been shown to be effective in solubilizing contaminants such as sodium, sulfate and chloride. The film boiling surface is collapsed in the high quality location in the bundle, wetting the previously dried out area. Downpowers will be scheduled dependent on source loading (i.e. condenser tube leak amount or degree of condensate demineralizer usage) and downpower effectiveness. As the hideout return is reduced, the time between downpowers is increased. Beginning approximately one month after startup, periodic downpowers will be conducted.

C. Long Term Corrective Actions

- Implement Boric Acid treatment in the secondary system to mitigate the alkaline/ caustic crevice environment.

  Boric Acid treatment will be implemented per PCR 92-13-SC-002.

- Mossbauer Analysis and/or Electrochemical Potential (ECP) Measurements.

  Both of these techniques can be used to determine whether an oxidizing environment is present in the SGs. Mossbauer Analysis determines the hematite/magnetite ratio in corrosion product samples, which is significant because corrosion rates are dependant upon ECP. ECP measurements are in situ measurements in the SG. ECP measurements will be considered as to its economic benefit, and will be evaluated by Chemistry and Nuclear Engineering.

- T_{HOT} Reduction

  PVNGS is currently involved in evaluating the benefits and impact of T_{HOT} Reduction. Elevated T_{HOT} is a contributing factor in the occurrence of IGA/IGSCC. This evaluation is projected to be completed in 1994.

- Chemical Cleaning

  Chemical cleaning presentations have been made by three vendors. A Request for Proposal is being completed for vendor solicitation. Nuclear Engineering is evaluating the economic benefit and timing of chemical cleaning.

- ATHOS III Run

  EPRI's ATHOS III model is being run to evaluate the impacts of varying flow, level and deposit parameters. This run is ongoing, and is expected to be completed by July 19, 1993. Based on the information from this analysis other operational corrective actions will be developed and evaluated.

- Improved Eddy Current Technology

  Improved technology is being researched to enhance sensitivity, detectability and speed of eddy current techniques.

D. Primary-to-Secondary Leakage Monitoring

The primary-to-secondary leakage monitoring program was designed to address three specific scenarios.

a. Low Level and/or Slowly Increasing Primary-to-Secondary Leakage,

b. Rapidly Increasing Primary-to-Secondary Leakage (as described in IN-91-43), and

c. Steam Generator Tube Rupture (No Leak Before Break).

This program was re-evaluated to ensure that it also encompassed the actual scenario observed during the Unit 2 Steam Generator Tube Rupture (SGTR) event. This effort validated the adequacy of the existing leakage monitoring program, however some areas for enhancement were identified.

The leakage monitoring program utilizes the installed Radiation Monitoring System (RMS) to detect the level and the rate of change of radioactivity in the secondary plant. The RMS provides continuous on-line monitoring capability to both Operations and RMS/ Chemistry personnel for detection of primary-to secondary leaks. The RMS monitors used for primary-to-secondary leak detection are described below:

- **Steam Generator Blowdown Radiation Monitors (RU-4 & RU-5)**

  Blowdown (downcomer sample point preferred) from each steam generator is monitored for liquid radioactivity (gamma emitters).

- **Condenser Vacuum Exhaust / Gland Seal Exhaust Radiation Monitor (RU-141)**

  The exhaust from the condenser vacuum pumps and gland seal exhaust blower discharge into a common line that is monitored for radioactive noble gases.

- **Main Steam Line Monitors (RU-139 & RU-140)**

  Dose rates on the main steam lines are monitored for increasing levels resulting from contaminated steam. While these monitors are not useful for detecting small leaks, they will provide an immediate indication of the larger leak rates associated with a SGTR event.

In addition to the RMS, the Chemistry Department also performs routine sampling in order to detect primary-to secondary leakage once per 72 hours to determine gross activity concentrations of the secondary coolant system (steam generators) per Technical Specification 3.7.1.4. This surveillance test uses gamma spectroscopy methods to determine radionuclide concentrations in the secondary coolant. This analytical method has a leak rate detection capability of 1.9 gpd (based on reactor coolant Iodine-131 activity of 4E-03 μCi/gm from fuel cycle data).

Under normal conditions, when no steam generator primary-to-secondary leakage is present, RU-141 trend data are reviewed for three-fold increases on at least a shiftly basis. In addition, setpoints on RU-141, RU-4 and RU-5 will alert personnel to increases in baseline monitor readings resulting from an increase in radioactivity levels in the secondary system. Routine chemistry sampling of the secondary system, performed in accordance with the Technical Specifications, will also alert personnel to the presence of low level concentrations of activity that may be below the sensitivity of the monitoring instrumentation. Based on the Unit 2 experience, low level leakage should exist for an extended period (on the order of several weeks) prior to significant increases in leak rate. Therefore, the existing monitoring program is adequate to detect the onset of primary-to-secondary leakage.

Procedure 74RM-9EF41, "Radiation Monitoring System Alarm Response", directs operations personnel to evaluate the secondary system for steam generator leakage in accordance with Procedure 4XAO-XZZ08, "Steam Generator Tube Leak", upon receipt of a valid alert or high alarm on any of the secondary system monitors. In addition, Chemistry personnel are also directed to perform a leak rate determination in accordance with Procedure 74CH-9ZZ66, "Determination of Primary to Secondary Leak Rate" and evaluate/monitor the leakrate in accordance with Procedure 74DP-9ZZ05, "Abnormal

Occurrence Checklist". If activity is detected during the performance of Procedure 74ST-9SG01, "Secondary System Activity Surveillance Test" and/or Procedure 74ST-9ZZ02, "Chemical Waste Neutralization Surveillance Test", chemistry personnel are directed to notify operations and perform a leak rate determination in accordance with Procedure 74CH-9ZZ66 and to evaluate/monitor the leak in accordance with Procedure 74DP-9ZZ05. Once primary-to-secondary leakage is identified and confirmed, the leakrate monitoring instructions and decision levels contained in Procedure74DP-9ZZ05 are implemented.

The monitoring instructions contained in Procedure74DP-9ZZ05 are based on leak rate levels. The higher the leak rate, the more aggressive the monitoring program. The decision levels for evaluating continued plant operation are contained in Procedure 4XAO-XZZ08. Additionally, this procedure requires evaluation of the impact of the leak rate on plant operations by operations personnel and plant management. Based on experience from the Unit 2 event, the leak rate levels for leak monitoring and evaluation will be changed as described below.

In addition to the enhanced leak monitoring program, specific administrative actions will be taken at various leak rates and rate of change. Between 0 and 10 gpd, the monitoring schedule as described previously will be conducted. When the leak rate is greater than 10 gpd and the leak rate increases by 50% within a 24 hour period, or a stable leak rate of 25 gpd is reached, a formal evaluation for continued operation will be conducted. The evaluation process will consider items such as RCS source term, stability of the leak, waste water processing abilities and the leak rate trend. If the leak rate exceeds 50 gpd, the Shift Supervisor initiates an orderly plant shutdown, and then informs plant management.

SGTR events (i.e., leak rates in excess of 40 gpm) are easily detectable by the main steam line monitors as evidenced by the Unit 2 event. Emergency Operations and Abnormal Occurrence procedures have been modified to ensure an accurate diagnosis of the event based on experience obtained from the Unit 2 event.

E. Program Enhancements

Based on experience gained from the Unit 2 event and re-evaluation of the leak rate monitoring program at PVNGS, several enhancements were identified. These enhancements either have been incorporated or will be incorporated into the existing program. The following summarizes these enhancements and provides a status for those that are in progress.

- Steam Generator Blowdown Radiation Monitors (RU-4 & RU-5)

  The sensitivity of the Steam Generator Blowdown Radiation Monitors, RU-4 & RU-5, have been improved by selecting the downcomer instead of the hotleg blowdown as the monitoring point. The downcomer sample stream, which is more concentrated,

offers greater overall sensitivity to detect primary-to-secondary leakage.Condenser Vacuum Exhaust Monitor, RU-141

- **Condenser Vacuum Exhaust Monitor (RU-141)**

  The alert setpoints for Condenser Vacuum Exhaust Monitor, RU-141, has been decreased to a level that is four times above background readings. The former setpoint value was based upon an allocated fraction of the site instantaneous dose rate limits per the off-site dose calculation manual and was several decades above typical baseline values. The new setpoints for RU-141 provide earlier alarms to plant operators in the event of increasing primary to secondary leakage than the previous setpoints.

- **Procedure 74CH-9ZZ66, Determination of Primary-to-Secondary Leak Rate, Method Priorities**

  Based on the Unit 2 SGTR event, as well as industry information, the preferred hierarchy of leak rate methodologies is to use a noble gas grab sample from the condenser vacuum exhaust for the most accurate leak rate determination. Iodine in the steam generator bulk water may be utilized if the leak is so small that noble gases are not detected in the condenser vacuum exhaust grab sample. However, industry information suggests that Iodine may hideout in the steam generator and therefore underpredict the actual leak rate. If noble gas can be detected in the condenser vacuum exhaust, it should be utilized for leak rate quantification, with Iodine being used for a qualitative confirmation of trend and to identify the leaking steam generator. The tritium method should be utilized in the absence of other radionuclides.

- **Leak Rate Administrative Action Plan**

  Dependent on the primary to secondary leak rate, the monitoring frequency will be increased. The monitoring program includes leak rate calculations, monitor trend data, and monitor setpoints. In addition, a formal evaluation for continued operation will be conducted when a 10 gpd leak rate increases by more than 50% in a 24 hour period, or a stable leak rate of 25 gpd is reached. At 50 gpd, the Shift Supervisor initiates an orderly plant shutdown, then informs plant management.

- **N-16 Monitoring**

  PVNGS Engineering has conducted a preliminary evaluation regarding N-16 monitoring instrumentation. As part of the evaluation, all major manufacturers of N-16 monitors were contacted. In addition, utilities that were currently using N-16 monitors were contacted to determine their installation and operational experience with the instrumentation. Based on the evaluation, the advantages of N-16 were determined to be a rapid response time and a source term that was only dependent on

reactor power. The disadvantages included a large error due to inaccuracies in estimating transport time through the steam generator and high installation cost.The short half life of N-16 makes quantifying the leak rate highly dependent on leak location. An accurate estimate of leak rate would still require correlation to conventional grab samples. PVNGS is still continuing to evaluate the use of N-16 monitors as a diagnostic tool for determining leak location and their benefit in giving a more timely notification of an increase in leak rate.

The radiation monitoring system (RMS) response and leak monitoring program at PVNGS was re-evaluated based on information obtained from the Unit 2 SGTR event. The evaluation verified that the current program adequately addressed early leak detection within the guidance of Information Notice 91-43. During the two weeks prior to the rupture, the RMS responded to minor leak transients. The main steam line monitors and the condenser exhaust monitor provided immediate indication of a SGTR when it occurred. It was concluded that for this event, the addition of N-16 monitors would not have provided any additional information that could have prevented the SGTR. Instead, the leak rate monitoring program was changed to:1) ensure correct diagnosis of a SGTR event by incorporating changes to the EOPs to use previous alarm indications and trend data: 2) provide earlier alarm indication by lowering the setpoint on the condenser exhaust radiation monitor and changing the sampling location for the steam generator blowdown monitors; and 3) to improve alarm response actions and leak rate estimates by utilizing condenser exhaust grab sample results as one of the primary leak rate calculation methods.

XII. SUMMARY/BASIS FOR RESTART

The Task Force has determined that PVNGS Unit 2 is safe to operate until the planned mid-cycle outage. A 100% bobbin coil eddy current examination of the entire steam generator and an extensive MRPC examination of the region where cracking occurred was conducted. All tubes with axial indications were removed from service by plugging, in accordance with the PVNGS administrative plugging criteria.

An evaluation per the requirements of Regulatory Guide 1.121 was performed. Based on this evaluation, it was concluded that the Unit 2 steam generators can be operated up to six (6) months from the start of Mode 1 operation without violating RG 1.121 required safety margins. Maintaining these safety margins ensures that operation of Unit 2 for this time period, with this steam generator tube degradation mechanism operative, does not introduce an unreviewed safety question.

Improved leakage monitoring will be implemented during this operating period. Enhancements in blowdown radiation monitors, condenser vacuum radiation monitors, increased leakage evaluations and trending based upon increasing leak rates, and a preferred hierarchy of leak rate methodology will ensure adequate and timely recognition of primary to secondary leakage.

Corrective actions have been and will implemented in order to reduce environmental factors determined to cause cracking. These actions are expected to reduce or mitigate the occurrence of cracking. Additional long term actions are planned to further mitigate the factors contributing to the occurrence of IGA/IGSCC.

In order to evaluate the safety significance of potential tube failure events during the upcoming six month operating period, a 10CFR50.59 evaluation was performed. The potential for a steam generator tube rupture event, as described in Section 15.6.3 of the PVNGS UFSAR, resulting from tube damage caused by IGA/IGSCC is considered to be negligible based on the assessment in this report. Additionally, there are no other accident scenarios outside the boundaries of Section 15.6.3 which could occur as a result of an undetected defect in the PVNGS steam generators.The worst case event which might occur during the six month operating cycle is a small, detectable, and stable tube leak. Therefore, the probability or consequences of a SGTR accident as defined in Chapter 15 of the UFSAR is not increased.

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XIV. APPENDICES

A. Design Evolution of Combustion Engineering Steam Generators

The Design Evolution of the System 80 Steam Generator Support Structure was reviewed for structural adequacy. The Steam Generators (SG's) at PVNGS are of the System 80 design and were manufactured by Combustion Engineering (CE) at the Chattanooga, TN facility during the late 1970's. The design of the System 80 SG internal tube bundle support structure evolved from the earlier SG's that CE designed, manufactured and sold to the various electric power utilities during the 1960's and 1970's. Tube supports are required at periodic intervals along the U-tube to prevent flow induced vibration which can result in fretting-wear and/or fatigue failure. The changes to the design from the earlier Units were basically a result of trying to balance two opposing design parameters.

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

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

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

1. "Early Units"

The "Early Units" consisted of Palisades, Mihama-1 (Westinghouse), and Fort Calhoun. The overall design of these SG's are too varied to be grouped into any specific category. However, they did have one common feature, the eggcrate design of their vertical support (VS) region was such that they used scallop bars to lock in the horizontal span of the tubes. (The VS region is basically an eggcrate support that lays on its side, with respect to the full and partial eggcrate supports below. However, to manufacture the same diamond pattern of the full and partial eggcrates in the VS region is unreasonable. Thus, the VS region uses a square eggcrate design with tubes in every other square. This increases tube spacing from 1" in the diamond pattern of the lower eggcrates to 1.25" in the VS region of the Early Units, which aided manufacturing [and aided Engineering by allowing the fluid to exit the bundle with less resistance]. However, the tubes in the VS region were still close enough that a

straight locking bar could not be used to lock the tube into its square eggcrate during assembly. A scalloped shaped locking bar was used).

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

2. "Series 67"

The first group of plants that had a common design were called the "Series 67" or the ~2800 MWt Units. This category consists of Maine Yankee, Calvert Cliffs-1&2, St. Lucie-1, and Millstone-2. (See Figure XIV -a)

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

The four partial support's consisted of 2 diamond patterned eggcrates below, and 2 drilled plates above. The top 2 partial supports were designed as drilled plates to provide a large amount of rigidity in the upper bundle (i.e. a very conservative design which had large margin of allowable stress).

The major change from the Early Units to the Series 67 Units was that spacing of the tubes in the VS region increased from 1.25" to 1.75" (which is the spacing still used in the newer generation of SG's). The spacing increase eliminated the use of the scalloped shape for the locking bars on the VS's (with the exception of Maine Yankee which has the scalloped bar design). The basis for the change was the observation in the field, that the scalloped shape locking bars were acting as crud traps. The flat locking bar had less crevice area than the half-moon shoe of the scallop bar. The significance of this change was the acknowledgment that crevices are undesirable (from either a corrosion or denting standpoint).

3. "3410 Series"

The next group of plants that had a common design were called the "3410 Series" or the 3410 MWt Units. Included in this category: ANO-2, Jersey Central (cancelled), SONGS-2&3, Waterford-2, and St. Lucie-2.

The 3410 Series upper bundle design (see Figure XIV -c.) consisted of the 3 partial eggcrates (PE's) and a segmented design of the BW's and VS's. This segmented design meant that the VS's and BW's were not joined together as one piece. The BW's were still one long piece, but the VS's were now each a single strip of carbon steel, leaving a gap between the BW and VS when viewed from the side. The width of each BW and VS was reduced to 2". The BW's were moved lower so that they were no longer laid across bend radius of the tubes. As a result, the bottom of the BW's no longer could come together to form a "V" design, since the point of the "V" would be too low in the bundle. Therefore, the BW's had a horizontal strip at the bottom called the "dogleg". The VS's were ventilated (i.e. had the elliptical flow holes punched through them for flow). The three PE's were all of the diamond pattern eggcrates design (i.e. no drilled plates). [Note that ANO-2 was a hybrid of the Series 67 and the 3410 Series designs. The unibody design was maintained, but the BW/VS unibody was raised higher to move the BW above the bend radius of the tubes (see Figure XIV -b.). The width of the BW's and VS's was reduced to 2" but the VS's were not ventilated. There were 4 PE's of the same design as the Series 67. Also, note the MWt rating: ANO-2 was <3410 MWt and of St. Lucie-2 was ~ 2800 MWt].

The basis for the design change was to minimize crevices/corrosion sites that had become evident in the Series 67 Units (and was an important issue for the industry in general at the time, as it is today). Thus:

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

b. It was noted that the VS's in a unibody design must lay across a bend radius for some of the tubes. So, the VS's were disconnected from the BW's, creating the segmented design. As a result, no VS would lay across a bend radius of any tube.

c. The width of the VS's was reduced from 4" to 2", and eliminated 50% of the crevice length in the VS region.

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

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

Note: The changes to the tube support structure design were made possible due to the increased availability of tube support vibration data. Dynamic coefficients made it possible to predict accurate flow forces. Test data was also yielding realistic damping values for use in tube stability analysis. The availability of high speed computers with sophisticated structural and thermal hydraulic flow codes made it easier to not over-design the support structure and therefore reduce the number of areas with potential for flow starvation. However, the long lead time in SG materials and fabrication affected which Units could benefit from the new design changes.

The result of these design changes in the 3410 Series was that the upper bundle had more flexibility. Some of the design margin was used, when comparing the 3410 Series to the Series 67 design; however analytically the 3410 Series remained stable and conservative. Test data supported the analytical conclusions that the margins were acceptable against instability resulting from flow induced vibration.

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

4. "System 80"

The next group of plants that have a common design were called the "System 80" or the 3810 MWt Units. This category consists of Palo Verde 1,2,&3, Yellow Creek(TVA)-1&2, WPPSS-3&5, Duke Power-1 through 6, Boston Edison Pilgrim-2, and the Palisades replacement SG's (See Figure III -a). Of these Units, only Palo Verde (PVNGS) and Palisades is in operation; the others were cancelled (Note that the Palisades replacement SG's were just placed in operation 1992).

The principle reason for the design change from the 3410 Units was corrosion and manufacturing techniques (See Figure III -f):

a. The number of PE's was reduced from 3 to 2. This eliminated 33% of the corrosion sites in the PE region.

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

c. VS-2,4&6 were shortened and allowed to be "free floating". This was changed to assist manufacturing and also reduced the number of crevice sites in the VS region.

d. The number of I-beam overhead supports was reduce from three to two. This was an ease in fabrication and was considered to have no bearing on normal operating conditions.

The result of these design changes was that the System 80 upper bundle would have slightly more flexibility when compared to the 3410 Series. The design, however, was considered stable and conservative, from an analytical point of view.

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

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

5. "System 80 +"

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

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

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

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

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

e. The hot leg flow distribution plate was eliminated as it was deemed not to impact blowdown or flow stability.

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

B. Description of Tube Examination Techniques

A detailed description and purpose of each tube examination method is described below.

1. Receipt Inspections

Radioactive tube sections are received by the laboratory and documented by the Health Physics technician. Tube sections are measured for length, checked for orientation and section markings.

2. Visual Inspections

Tube sections are visually examined with a low power stereomicroscope to identify and characterize any tube degradation on the tube. Tube deposit visual characteristics are also determined, and any apparent damage from the tube pulling process is noted. the tube sections are photographed in the as-received condition. Areas of interest are also photographed for review and record purposes. These areas may be selected for further investigation in addition to planned areas of interest.

3. **Eddy Current Testing (ECT)**

Tube sections are selected for ECT testing using both the Bobbin Coil and the Rotating Pancake Coil (RPC) to precisely verify and locate tube defects for investigation. Qualified ECT personnel perform the inspections and analyze the data. The ECT data is then used to both identify defect areas and to correlate to field ECT findings.

4. Radiography

This is performed on tube sections with defect areas of interest. The primary purpose is to verify the defect location and dimensional characteristics. Radiography is not sensitive to corrosion forms of degradation such as intergranular attack (IGA) or intergranular stress corrosion cracking (IGSCC).

5. Dimensional Measurements

These measurements are performed to determine diametrical and tube wall thickness variations, and to characterize any tube bend or bow. This information is needed to verify tube wall thickness specifications and to locate any bowing which may contribute to degradation processes.

6. Deposit Removal and Analysis

Selected areas of tube deposit formations are identified and removed from the tube by mechanical scrapping for future chemical analysis. Deposit locations and physical characteristics are noted. Deposits are then submitted for chemical analysis to identify the chemical composition and any chemical contaminants which may be contributing to a postulated corrosion degradation mechanism. The extent of deposit chemical analysis includes the following:

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

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

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

7. <u>Burst Testing</u>

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

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

b. Sectioning Diagram - a sectioning diagram is developed for deciding which sections are to be studied under the scanning electron microscope (SEM) and by Auger Electron Spectroscopy (AES) and X-Ray Photoelectron Spectroscopy (XPS).

c. SEM - provides high magnification examination of the crack or wear surface. This allows the mode of cracking to be determined, i.e., IGSCC or fatigue cracking. If the cracking is intergranular then this is clearly visible under the SEM, as the surface appears like rock candy. The examination is crucial for this aspect alone. The crack depth profile is also determined using the SEM. This information is important both for eddy current data analysis and corrosion attack characterization. The SEM also has the capability of performing qualitative chemical analysis of the defect surface and any associated deposits using the Energy Dispersive

Spectroscopy (EDS) equipment. EDS is based on x-ray fluorescence resulting from bombardment of the sample with an electron beam.

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

e. XPS - provides elemental/compound analysis of thin corrosion films. Adds additional vital information regarding the chemical attack at the crack surface by identifying how elements are chemically combined. This information is useful in identifying corrosion products which are also indicative of the local crevice environment.

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

8. <u>Tube Material Characterization</u>

This work is specified to be performed to determine the material property conformance to specifications. Material that is not in conformance with tube material specifications may be more susceptible to failure by either corrosive or mechanical means.

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

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

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

d. Tensile Testing - performed to verify mechanical properties.

9. Additional Testing

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

In summary, a steam generator tube failure analysis is a effective method for determining tube degradation modes and providing data for corrective action evaluation. The investigation process is vigorous and resource intensive. Results must be carefully evaluated against plant data, past field experience and laboratory studies involving Alloy 600 tube corrosion.

C. Statistical Evaluation of ECT Program

1. Introduction

APS Nuclear Fuel Management was requested to statistically evaluate the Unit 2 steam generator Bobbin Coil and MRPC data to determine what conclusions can be made based on the currently proposed steam generator tube inspection plan. Following, the Unit 2 SG tube rupture event (Spring 1993), Bobbin Coil inspections were performed on 100% of the steam generator tubes in both of the Unit 2 steam generators. These examinations resulted in the identification of a concentrated number of tube axial indications within a specific area of the steam generators (between levels 08H and the first vertical support above the batwing plus the 07H support, on the hot leg side, on the periphery of the generators above row 90). Root cause evaluation of the cause of these defects indicates that the steam flow conditions in this area may result in chemical deposits on the tubes in this location. This calculation is performed based upon eddy current results available as of 7 July, and should be reperformed if a substantial number of additional flaws are subsequently identified. However a sensitivity analysis was done to verify that the results are not sensitive to the identification of a small number (less than 4) of additional flaws within the arc region.

2. Evaluation of Tube Indications

Data analysis of Unit 2 steam generator Axial Indication (AI) data above the 08H area (This is area where Unit 2 tube failure occurred, and is the area where the steam generators have experienced an unusual amount of axial indications)

Tube data in high risk region (Approximately 3800 tubes from 8H to the first vertical support above the batwing, plus the 7H support) as of July 7, 1993 is presented below.

Steam Generator	Number of Bobbin Coil Midspan Indications	Number of MRPC[1] Midspan Indications	Number of Bobbin Coil Support Indications	Number of MRPC Support Indications	Total Bobbin Coil Indications	Total Number of MRPC Indications
SG 21	3	13	3	2	6	15
SG 22	23	54	31	19	54	73
Total	26	67	34	21	60	88

Notes:

(1) Additional # of MRPC axial indications in high risk arc. The high risk arc was reinspected using MRPC method and additional axial indications were found that were not detected by Bobbin Coil inspection. Single volumetric indications are neglected since they are considered not to be precursors of tube rupture event.

3. Evaluation of Tube Axial Indication Data

Of 62 Bobbin Coil axial indications above the 08H area, 61 occurred in the region identified as the high risk region which has or will be subjected to MRPC evaluation. The remaining area of the steam generator, has only one Bobbin Coil axial indication (SG22, R151C90). The number of additional axial flaws in this region which would be detected if MRPC inspections were performed in this region can be estimated based upon our knowledge of the following:

a. The number of Bobbin Coil indications in this region (only 1 indications in the low risk region of the approximately 21,714 tubes inspected in SGs 21 and 22), provides data which can be utilized to construct a distribution reflecting our knowledge on the probability that a single tube has developed a crack which is detectable by Bobbin Coil inspection. It is assumed that all tubes in the low risk region have an equal likelihood of developing a crack, and that the number of cracks observed can therefore be modeled as a Poisson process. This is an important analysis assumption, as depending on the root cause of failure, a transition zone may exist between the high risk area and the low risk area with an intermediate failure rate. Particularly, when axial indications are located near the zone boundaries, this assumption can be called into question. For this reason it is desirable that the high risk zone boundaries comfortably encompass all axial indications, and/or that the zonation boundaries be based on some physical parameter such as stress less than some critical stress level below which the crack propagation rate is dramatically decreased.

Based upon the zone boundaries as of July 7, all of the Bobbin Coil axial indications (particularly the midspan indications which are the main concern) are well inside the zone boundaries radially and vertically, and this assumption is judged to be reasonable. Development of a distribution describing our knowledge about the rate of Bobbin Coil defects outside of the high risk arc based on the scope of sampling which is presently scheduled:

There was 1 total axial Bobbin Coil indication in approximately 21,714 tubes sampled in the area of concern outside of the defined high risk arc region (excludes tubesheet and 01H support faults). The median value for the rate of Bobbin Coil support indications outside the arc region was therefore estimated as 4.61E-5 defects/tube (1/21,714). The 95% upper confidence value was estimated by solving the binomial equation for the value of p which would only have a 5% chance of observing 1 or less failures in 21,714 tubes.

(1-p)**21714 + 21714 * p * (1-p)**21713 =.05

Solving for p, a value of p of 2.19E-4 results in a 5% chance of detecting 1 or fewer failures. Therefore the 95% confidence value on p (the rate of support/ batwing axial defects which are detectable by Bobbin Coil inspection. Error factor = 95th/median = 4.75

Development of a distribution describing our knowledge about the rate of Bobbin Coil mid-span defects outside of the high risk arc based on the scope of sampling which is presently scheduled (Interspan defects are a particular concern and defects in this region are more likely to result in significant amounts of leakage).

There were no interspan defects identified by Bobbin Coil inspection outside of the high risk region in approximately 21,714 tubes inspected.The median value was therefore estimated as 2.30E-5 defects/tube (0.5/21,714). The 95% upper confidence value was estimated by solving the binomial equation for the value of p which would only have a 5% chance of observing no failures in 21,714 tubes.

(1-p)**21714 = .05

Solving for p, a value of p of 1.38E-4 results in a 5% chance of detecting 1 or fewer failures. Therefore the 95% confidence value on p = 1.38E-4 defects/tube. Error Factor = 95th/median = 6.0

b. The relative proportion of axial indications detected by MRPC which are not detected by Bobbin Coil inspection, versus the number detected by Bobbin Coil inspection. Within the high risk region MRPC inspections are being completed,

and the number of axial indications detected by MRPC which were missed by the Bobbin Coil inspection can be compared with the number of Bobbin Coil indications within the same region to develop a confidence range on the relative frequency of defects indicated only by MRPC. It is judged that the relative proportion of axial indications indicated by MRPC inspection versus Bobbin Coil for both support flaws and midspan flaws would be expected to be the same in the low risk region as the high risk region. Development of a distribution describing our state of knowledge of the ratio of the probability of a defect detectable by MRPC but not by Bobbin Coil relative to the probability of a Bobbin Coil detectable fault.

This distribution was constructed separately for midspan and support/batwing defects since the data indicated that a separate factor was appropriate for midspan versus support/batwing defects.

4. **Support/Batwing MRPC to Bobbin Coil ratio:**

For support/batwing defects there were (from section C.2) 34 Bobbin Coil indications, and 21 additional defects identified by MRPC inspection The median probability that a specific tube in the low risk region has a MRPC fault is estimated directly from the ratio of the additional MRPC defects detected by MRPC inspection of the high risk arc to the number of Bobbin Coil defects in the same area times the probability that the same tube has a Bobbin Coil detectable fault [this distribution has been constructed inC.3.a above]. In this case the relative ratio of MRPC defects (missed by Bobbin Coil) is 21/34 or .618.

Calculating an upper bound ratio of MRPC defects (not detected by Bobbin Coil inspection) to Bobbin Coil defects is somewhat more involved. However a lower bound estimate of the proportion of defects which are detectable by Bobbin Coil (which corresponds to the largest ratio of MRPC defects which are missed by Bobbin Coil inspection) can be estimated from Section 5.4 of NUREG/CR-4350 Volume 6:

Define p = BC/(BC + MRPC) where BC is the # of Bobbin Coil detected faults in high risk area of SG21 and SG22, and MRPC is the number of additional defects identified by MRPC inspection in the same area

$$p_L = 34/[34 + 22\, F_{.05}\,(44,68)] = .498 = BC/(BC + MRPC_U)$$

Solving for MRPC; $MRPC_U = 1.01 * BC$, and therefore the upper bound ratio of MRPC defects not detected by Bobbin Coil defects is 1.01.

The distribution reflecting our knowledge on the relative likelihood of MRPC support/batwing defects relative to a Bobbin Coil detectable defect, then has a median of 0.618

and an upper bound of 1.01. Fitting a lognormal distribution, the Error factor is 1.63 (95th/median) with a median of 0.618.

5. **Interspan MRPC to Bobbin Coil ratio (Base Case Results)**

For midspan (or interspan) defects there were (from section C.2) 26 Bobbin Coil indications, and 67 additional defects identified by MRPC inspection The median probability that a specific tube in the low risk region has a MRPC fault is estimated directly from the ratio of the additional MRPC defects detected by MRPC inspection of the high risk arc to the number of Bobbin Coil defects in the same area times the probability that the same tube has a Bobbin Coil detectable fault [this distribution has been constructed in C.3.a above]. In this case the relative ratio of MRPC defects (missed by Bobbin Coil) is 67/26 or 2.58.

Calculating an upper bound ratio of MRPC defects (not detected by Bobbin Coil inspection) to Bobbin Coil defects is somewhat more involved. However a lower bound estimate of the proportion of defects which are detectable by Bobbin Coil (which corresponds to the largest ratio of MRPC defects which are missed by Bobbin Coil inspection) can be estimated from Section 5.4 of NUREG/CR-4350 Volume 6.

Define p = BC/(BC + MRPC) where BC is the # of Bobbin Coil detected faults in high risk area of SG21 and SG22, and MRPC is the number of additional defects identified by MRPC inspection in the same area

$$p_L = 26/[26 + 68\ F_{.05}\ (136,52)] = .202 = BC/(BC + MRPC_U)$$

Solving for MRPC; $MRPC_U = 3.95 * BC$, and therefore the upper bound ratio of MRPC defects not detected by Bobbin Coil defects is 3.95. The distribution reflecting our knowledge on the relative likelihood of MRPC support/batwing defects relative to a Bobbin Coil detectable defect, then has a median of 2.58 and an upper bound of 3.95. Fitting a lognormal distribution, the Error factor is 1.53 (95th/median) with a median of 2.58.

6. **Interspan MRPC to Bobbin Coil ratio (Sensitivity Results)**

Since MRPC inspections are not complete in SG22, a sensitivity analysis was performed to show that the results will not be invalidated if a small number (in particular 3) of additional interspan indications are subsequently identified within the Arc region. Assuming an additional 3 interspan defects identified by MRPC the data (from section C.2) would reflect 26 Bobbin Coil indications, and 70 additional defects identified by MRPC inspection

The median probability that a specific tube in the low risk region has a MRPC fault is estimated directly from the ratio of the additional MRPC defects detected by MRPC inspection of the high risk arc to the number of Bobbin Coil defects in the same area times the probability that the same tube has a Bobbin Coil detectable fault [this distribution has been constructed in C.3.a above]. In this case the relative ratio of MRPC defects (missed by Bobbin Coil) is 70/26 or 2.69.

Calculating an upper bound ratio of MRPC defects (not detected by Bobbin Coil inspection) to Bobbin Coil defects is somewhat more involved. However a lower bound estimate of the proportion of defects which are detectable by Bobbin Coil (which corresponds to the largest ratio of MRPC defects which are missed by Bobbin Coil inspection) can be estimated from Section 5.4 of NUREG/CR-4350 Volume 6.

Define p = BC/(BC + MRPC) where BC is the # of Bobbin Coil detected faults in high risk area of SG21 and SG22, and MRPC is the number of additional defects identified by MRPC inspection in the same area

$$p_L = 26/[26 + 71\ F_{.05}\ (142,52)] = .202 = BC/(BC + MRPC_U)$$

Solving for MRPC; $MRPC_U = 4.10 * BC$, and therefore the upper bound ratio of MRPC defects not detected by Bobbin Coil defects is 4.10. The distribution reflecting our knowledge on the relative likelihood of MRPC support/batwing defects relative to a Bobbin Coil detectable defect, then has a median of 2.69 and an upper bound of 3.95. Fitting a lognormal distribution, the Error factor is 1.52 (95th/median) with a median of 2.69.

7. **Determination of the distribution of the probability that a specific tube in the low risk region has a axial indication which would be detected by MRPC inspection but which was not detected by Bobbin Coil inspection**

The probability that a specific tube in the low risk region has an axial indication which would be detected by MRPC inspection which was not detected by Bobbin Coil inspection can now be estimated as the product of the appropriate distributions developed above:

a. The distributions developed in Section C.3 describing the probability that a specific tube has a Bobbin Coil detectable support or midspan flaw.

b. The distributions developed in Section C.3 describing the relative likelihood of a MRPC detection relative to Bobbin coil for support and interspan indications.

These two lognormal distributions were combined by Monte Carlo simulation using the Uncertainty module CHEMRISK program. The results are summarized below:

Table 1: Results for the Rate of Defects (Free Span and Support) Outside the High Risk Arc

Total # of MRPC Faults Detected in High Risk Area	Median Probability that a specific tube in Low Risk Region has an MRPC Fault	Corresponding Mean Probability Value
88	1.053 E-4	1.570E-4
91	1.082E-4	1.591E-4

Table 2: Results for the Rate of Free span Defects Outside of the High Risk Arc

Additional MRPC Free span Indications Detected in High Risk Arc	Median Probability that a Specific Tube in the Low Risk Region has a Free span MRPC Fault	Corresponding Mean Probability Value
67	6.009E-5	1.114E-4
70	6.271E-5	1.161E-4

8. **Calculation of 95% Confidence Level on the Number of Additional Defects in the Low Risk Region which would Be Detected if MRPC Inspections Were Performed**

From the results in section C.7 it is relatively straight forward to calculate the number of failures that would be expected to occur in the low risk region of a steam generator with any desired Confidence Level. A computer program was written which takes the distribution of additional MRPC defects in the low risk region, discretizes the failure probability distribution (20% weight given to the 20th percentile value; 10% weight to the 40th, 50th, 60th, 70th and 90th percentile values; 5% weight given to each of the 25th, 30th, 75th,80th and 95th percentile values; 2.5% weight given to the 97.5 percentile value, 1.5% weight given to the 99th percentile value; 0.5% weight given to the 99.5th percentile value and 0.5% weight given to five times the 99.5 percentile value), and calculates based on this discretized distribution the likelihood of between 1 and 20 indications. The Results on 95% Confidence Levels on the Number of Faults in the Low Risk Region are summarized below:

Table 3: Results for the Total Number of Defects Outside of the High Risk Arc

Additional MRPC Axial Indications Detected in High Risk Arc	95% Confidence Values on the # of Additional Axial Indications (Support & Mid span) that MRPC Would Identify in the Low Risk Region of SG 21 or 22
88	7
91	7

Table 4: Results for the Number of Free span Defects Outside of the High Risk Arc

Additional MRPC Free Span Axial Indications Detected in High Risk Arc	95% Confidence Values on the # of Additional Free span Axial Indications that MRPC Would Identify in the Low Risk Region of SG 21 or 22
67	6
70	6

9. Results

The results of this analysis are summarized above. Based on the SG eddy current results as of July 7, 1993 there is high confidence that there are only a limited number of axial indications (7 or less total indications and 6 or less interspan defects) in the low risk region of the steam generators that would be uncovered by MRPC inspection.

D. Industry Review

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

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

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

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

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

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

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

2. **Maine Yankee Atomic Power Station (CE)**

Maine Yankee was shut down on December 14, 1990 when a 1.4 GPM primary to secondary leak was detected. The leak was identified in the #1 steam generator on December 12, and gradually increased from .0006 GPM to 1.4 GPM when the shutdown was performed. The source of the leak was determined to be a 2-inch long axial crack at the apex of the U-bend in the steam generator tube. This location was described as a "steam blanket region" where the batwing supports restricted flow, permitting a steam void to form and contaminants to be deposited on the tube surface.

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

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

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

4. **Doel Unit 4 (Belgium)**

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

5. EPRI

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

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

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

- 17 plants containing 59 steam generators were surveyed.
- 15 of 17 plants had identified tubes with free-span OD indications.
- 11 of 17 plants had plugged tubes with freespan OD indications.
- 400 bobbin and/or MRPC identified free span OD indications were found to have been randomly distributed.
- 105 free span defects were plugged in the 17 plants.
- 92% (97/105) of the defects were plugged in the four Duke units.
- 8% (8/105) of the defects were plugged in the seven other units.
- 21 pluggable defects were found by MRPC only.
- 42 free pan defects not found by ECT during the previous inspection resulted in plugged tubes.
- 135 sizeable free span indications were re-identified during one or more cycles.
- 11% (12/105) of the pluggable free span defects > 39% were found after not being identified during the previous inspections.

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

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

6. **Dominion Engineering**

Based on a recommendation of EPRI, Dominion Engineering was contacted via telephone on 4/20/93 and 4/25/93 for additional information regarding the study they had performed for EPRI (see previous pages). It was Dominion's opinion that the best information regarding midspan cracking could be provided by the McGuire facility (see previous reference). Dominion stated that polishing and straightening stresses could be 10 -15 ksi (thousand pounds per square inch) but that scratches could not be ruled out as a cause. Dominion stated that the problems experienced at Doel were aggravated by the existence of a lead blanket in the steam generators.

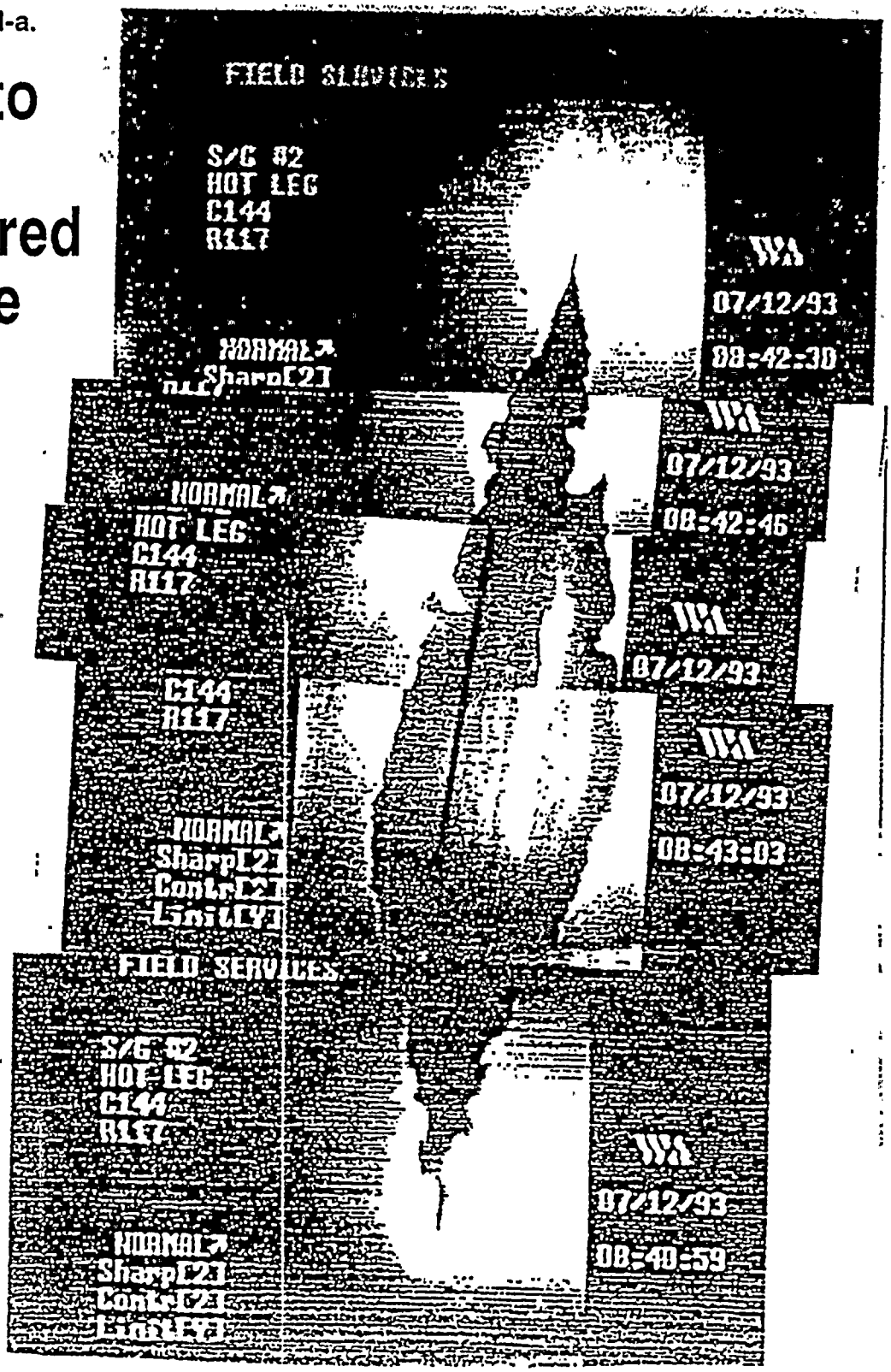
It was their recommendation that PVNGS contact Florida Power and Light (St. Lucie) for additional information regarding their experiences with steam generator tube cracks/indications. Dominion stated that they were aware of eggcrate cracks where line contacts between a tube and eggcrate could develop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

7. **Florida Power and Light**

Based on the recommendation of Dominion Engineering, Florida Power and Light was contacted on 4/25/93. FP&L Industry Review stated that St. Lucie had not identified any mid-span indications on their steam generator tubes. They stated that the cracking problems occurring at St. Lucie were outer diameter stress corrosion cracking (ODSCC) and IGSCC at supports. They stated that hundreds of defects were present in the eggcrates. They had also observed steam blanketing on horizontal runs due to the vertical straps acting as steam traps (NOTE: The System 80 design has ventilating holes in the straps to prevent this from occurring). FP&L suggested that lift off of ECT from ovalization should be evaluated as to whether such action could cause the bobbin to miss an indication. FP&L also stated that Turkey Point had hundreds of random burnishing points but, to date, no cracking had been observed at mid-span.

FIGURE I-a.

Photo of Ruptured Tube



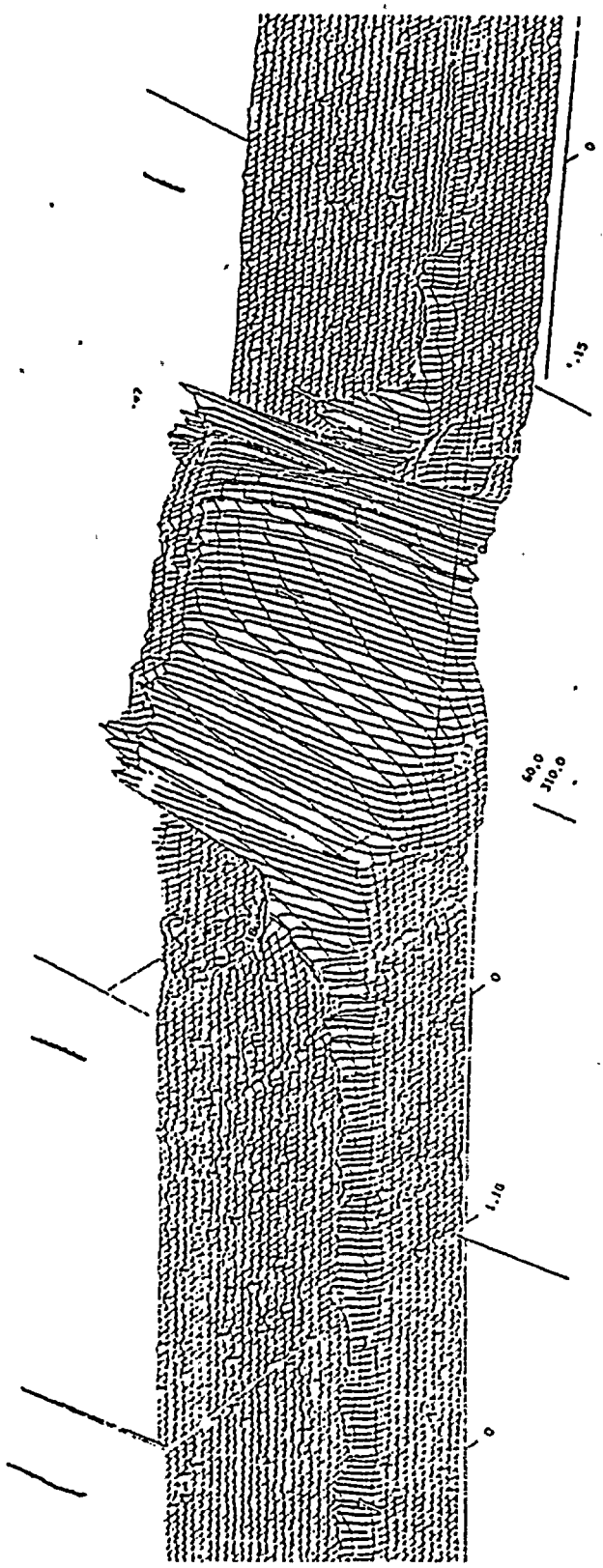


FIGURE I-b.

Eddy Current Axial Crack Signature of Failed Tube

Figure II.a

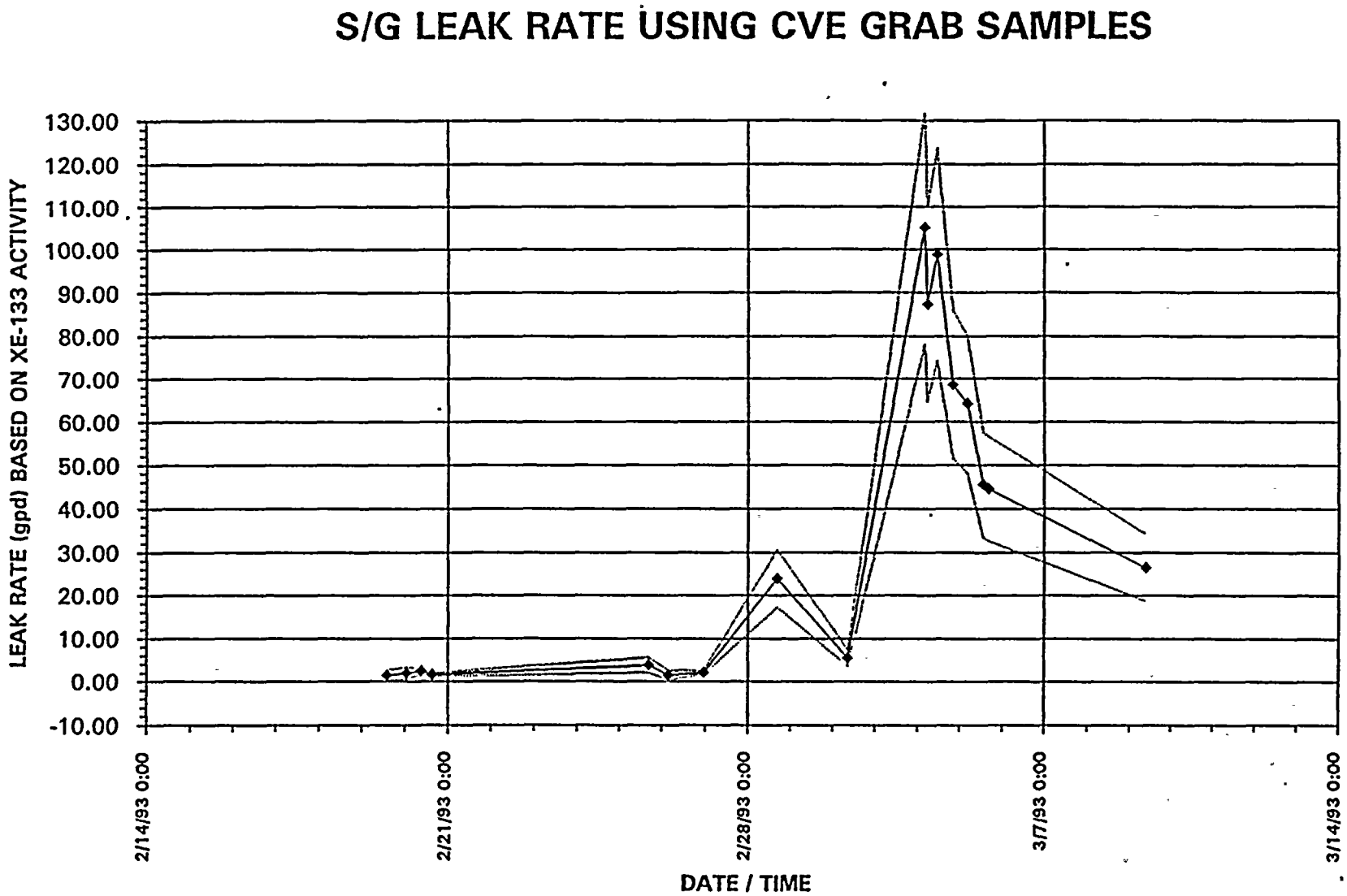

S/G LEAK RATE USING CVE GRAB SAMPLES
LEAK RATE (gpd) BASED ON XE-133 ACTIVITY
130.00
120.00
110.00
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
-10.00
2/14/93 0:00
2/21/93 0:00
2/28/93 0:00
3/7/93 0:00
3/14/93 0:00
DATE / TIME

Figure II.b

S/G #2 LEAK RATE USING TRITIUM

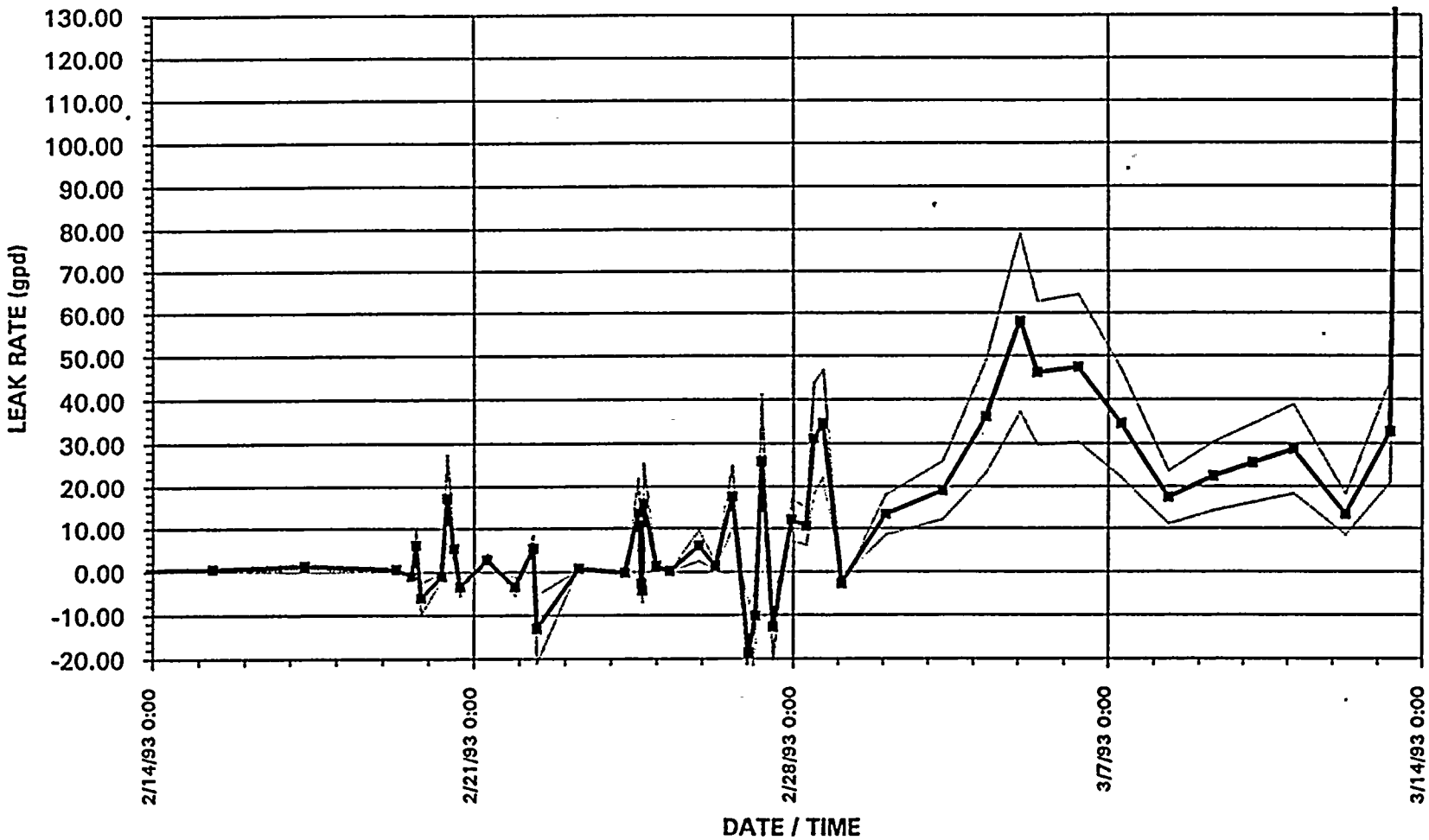
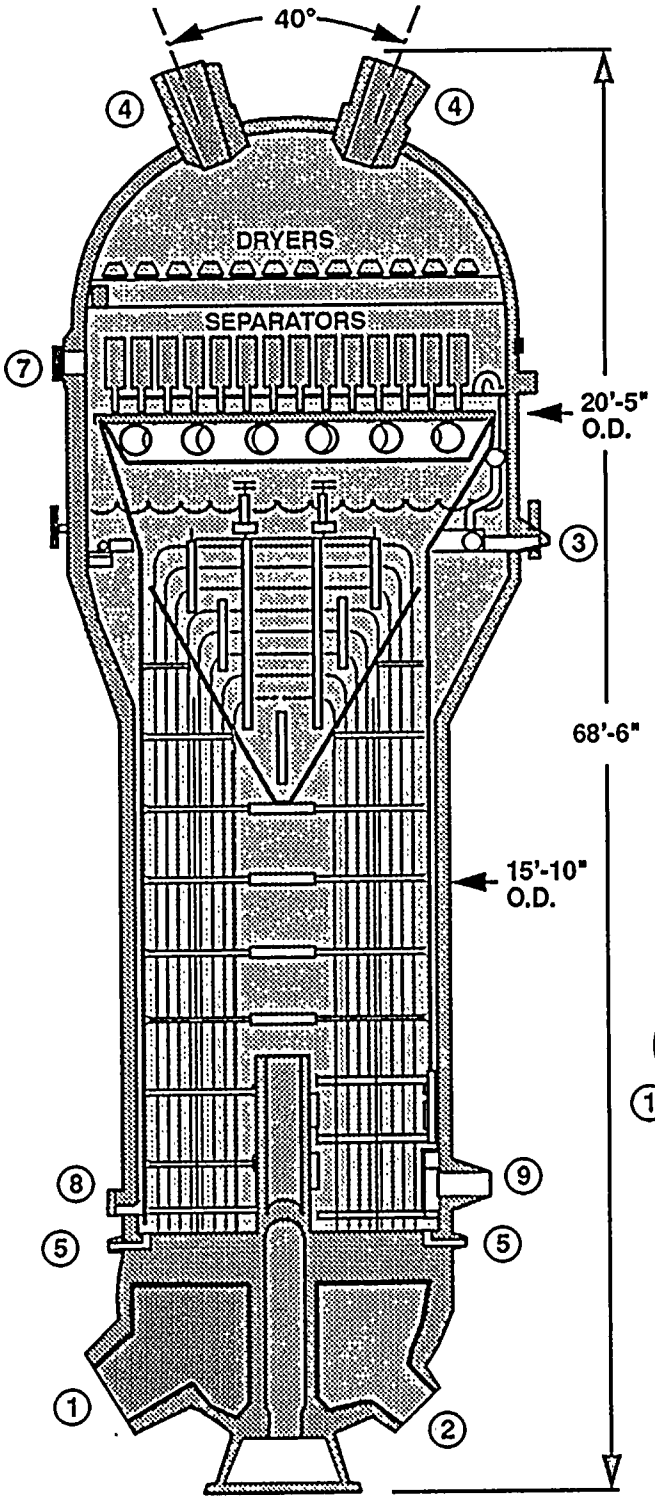
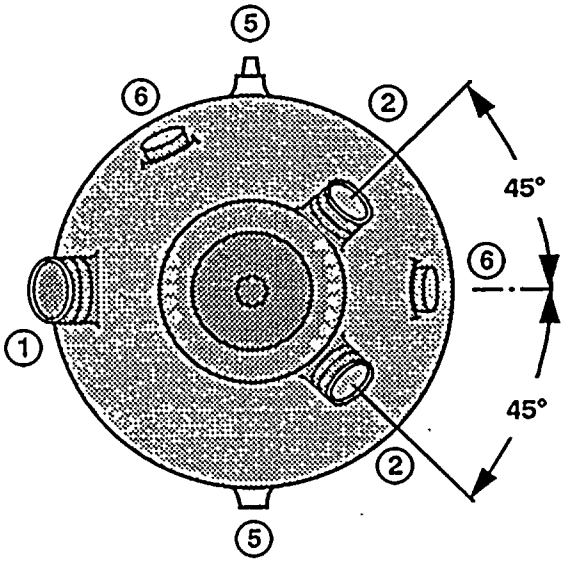


FIGURE III-a

SYSTEM 80 STEAM GENERATOR



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



BOTTOM VIEW OF
STEAM GENERATOR

SYSTEM 80 STEAM GENERATOR TUBES

TRIANGULAR PITCH CONFIGURATION

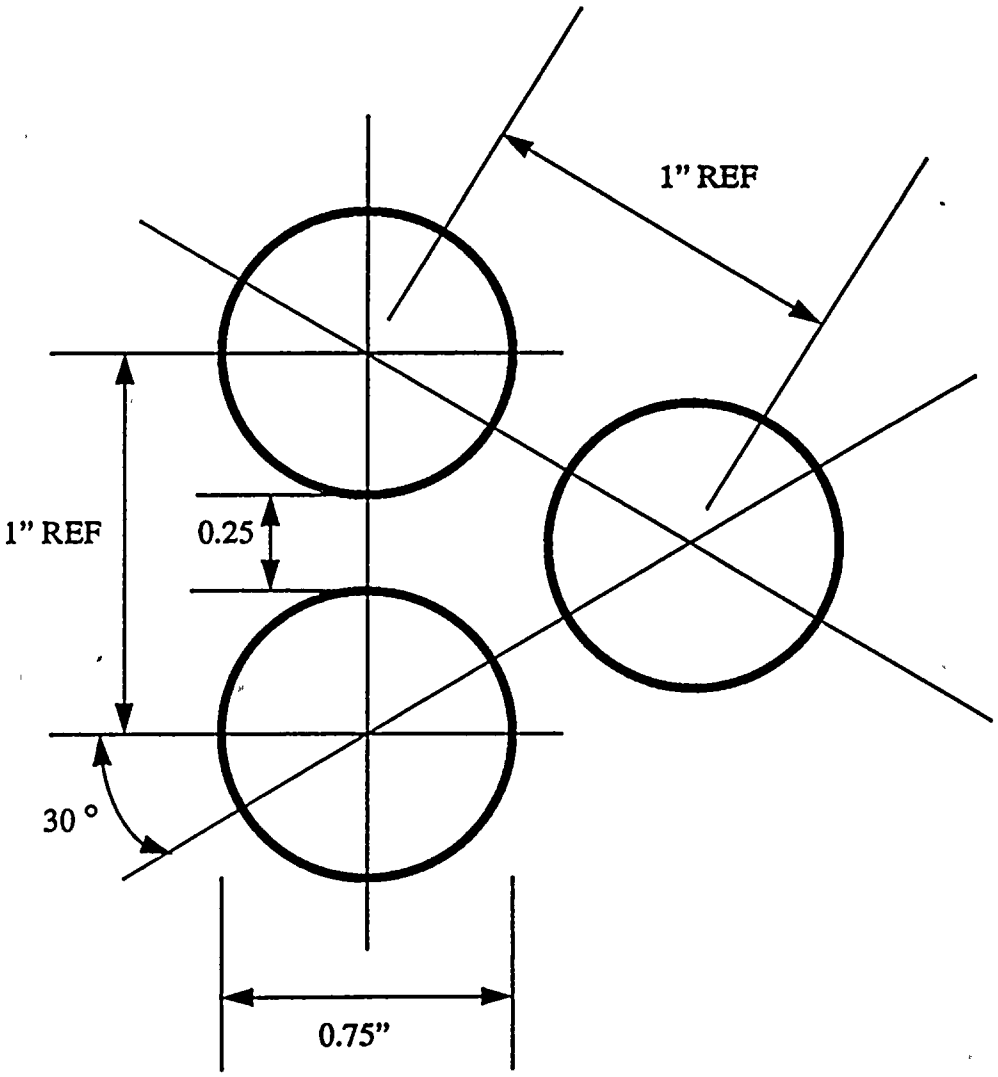


FIGURE III-b

STEAM GENERATOR TUBE SUPPORT DIAGRAM

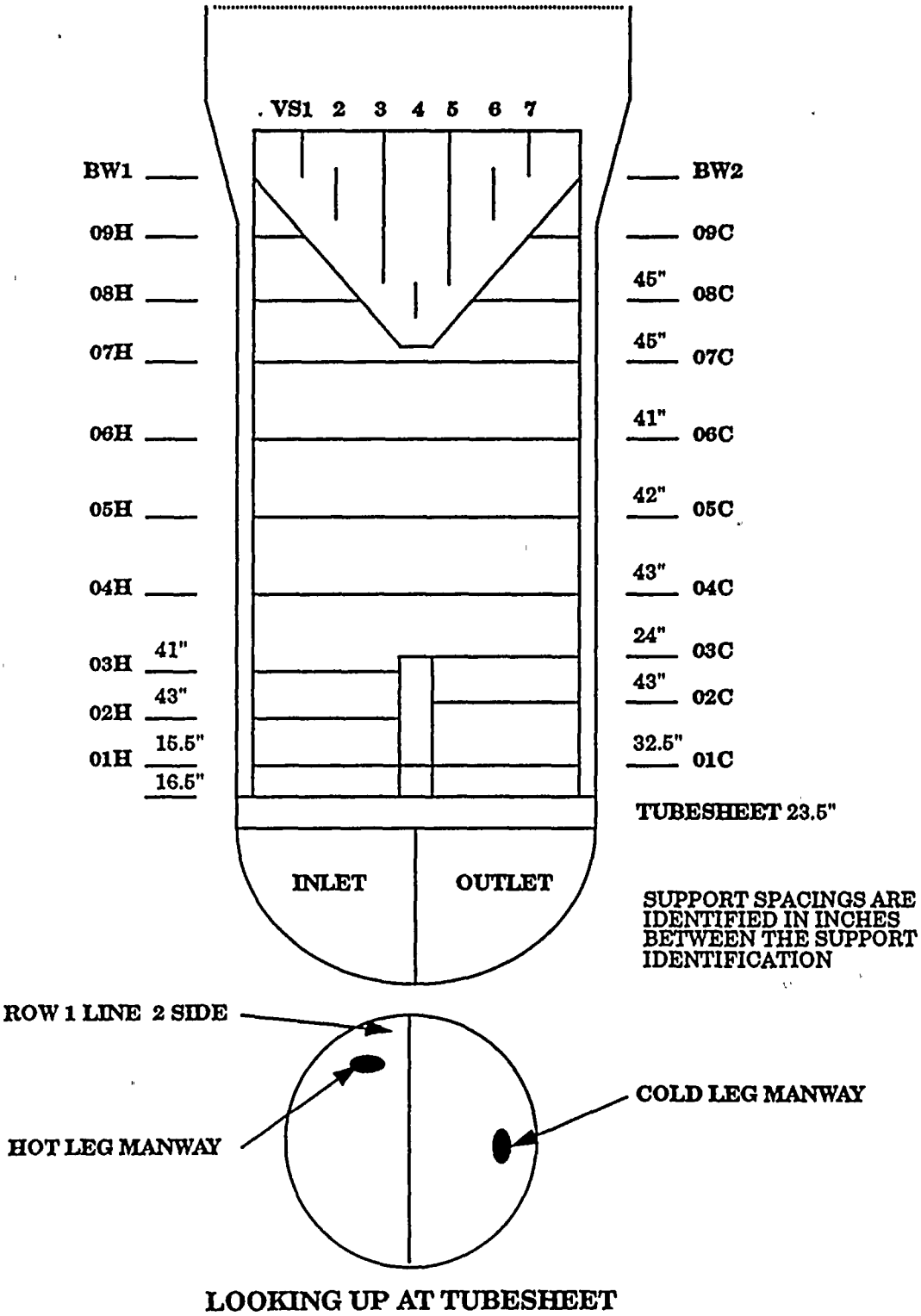


Figure III-c

FIGURE III-d

Eggcrate Support Detail

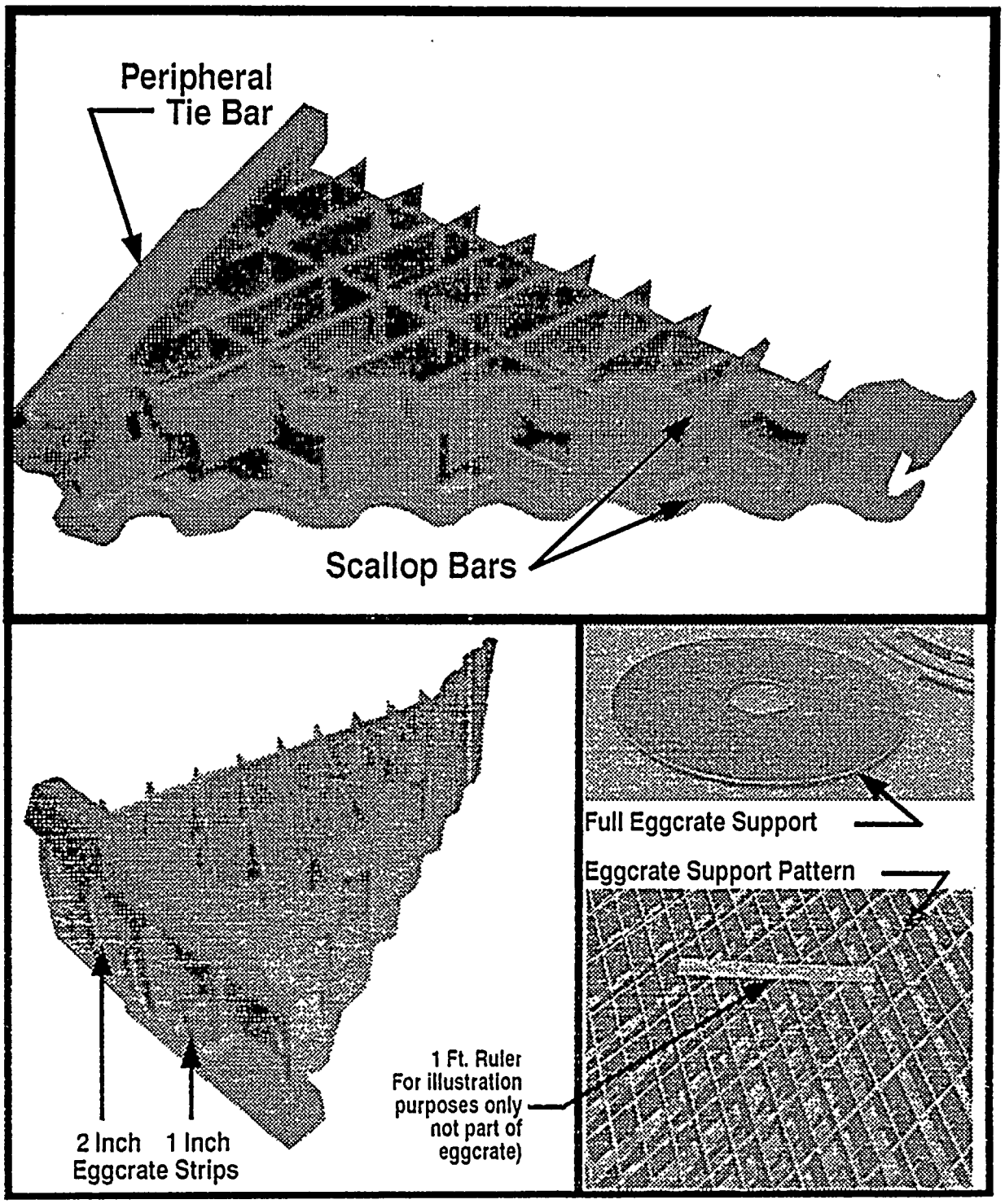
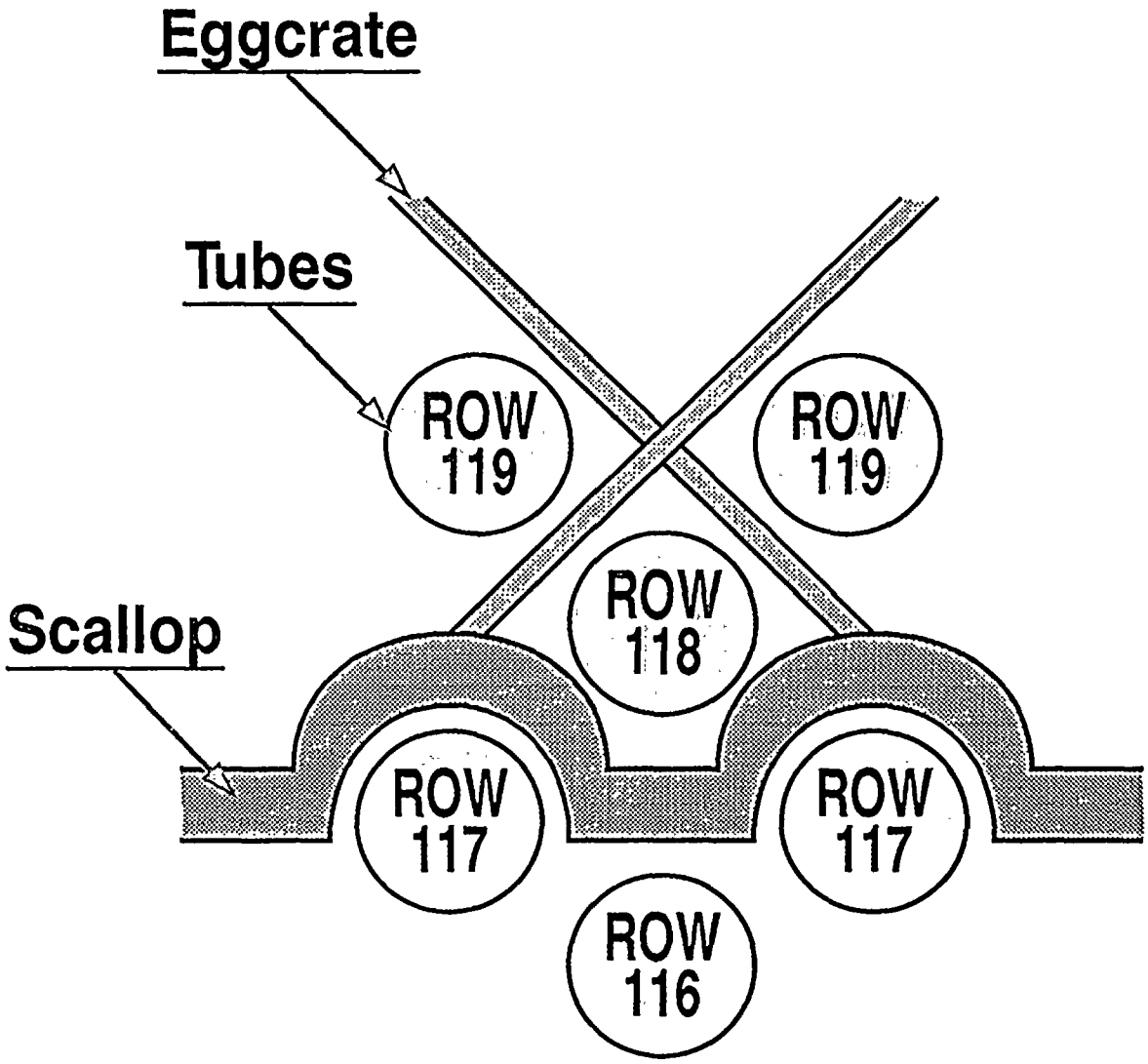


FIGURE III-e.

Partial Eggcrate 09H Scallop Arrangement



NOTE:

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

Eggcrate

FIGURE III-f.

Palo Verde Upper Tube Bundle Supports

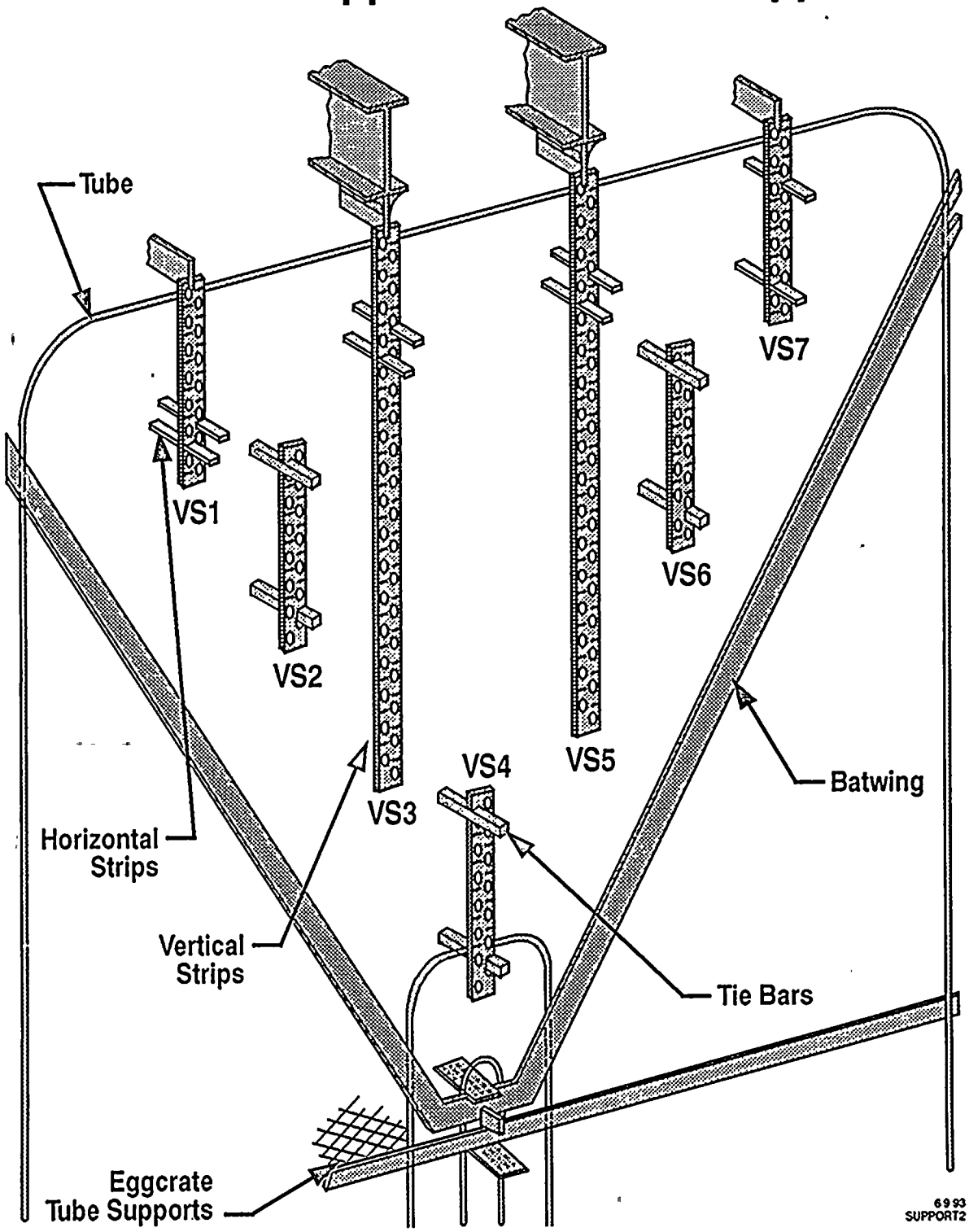
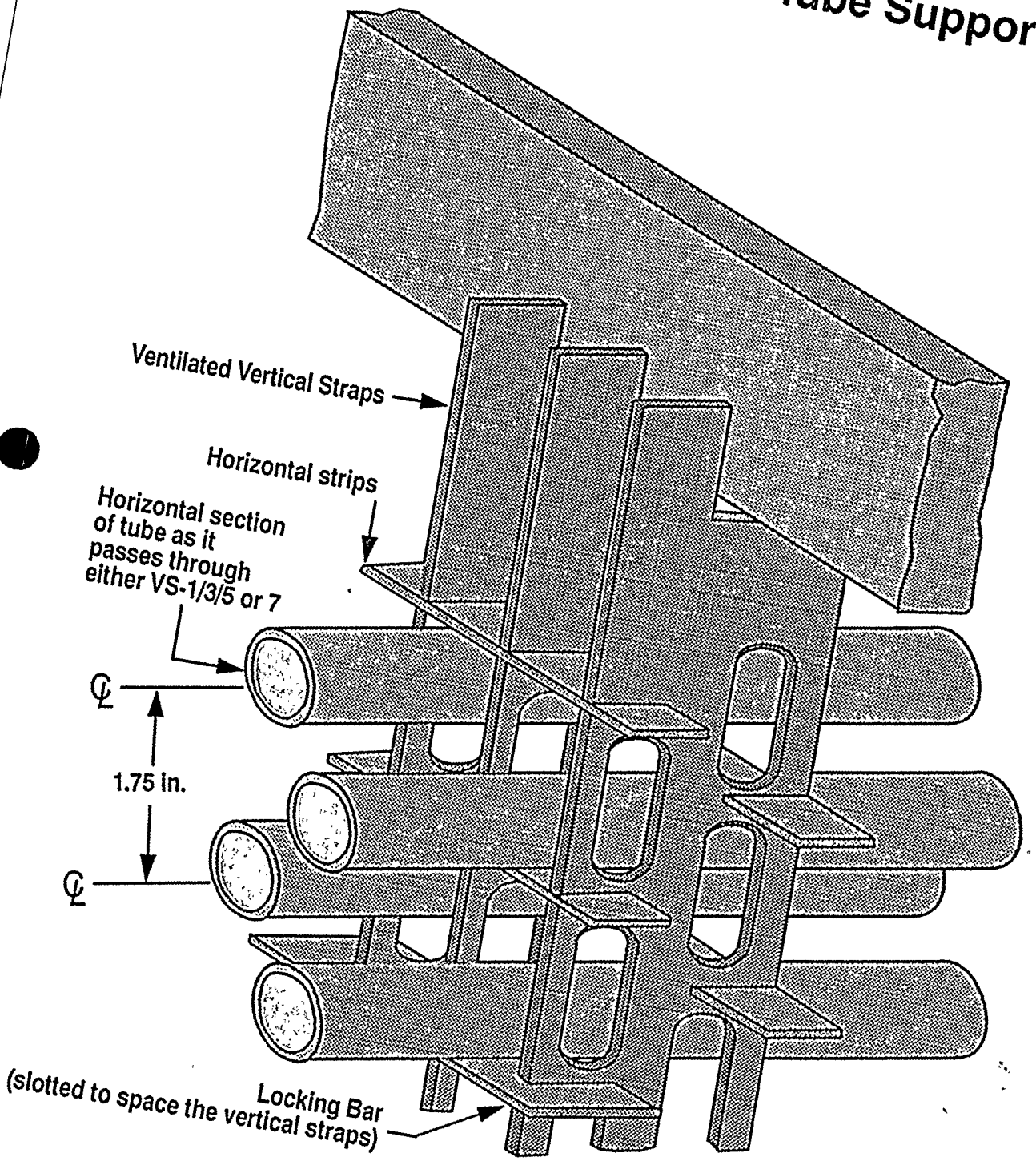


FIGURE III-g.

ABB-CE Ventilated Vertical Tube Support Grid



7193
SUPPORT1

FIGURE III.h.

Secondary Fluid Flowpaths of CE System 80 Steam Generator

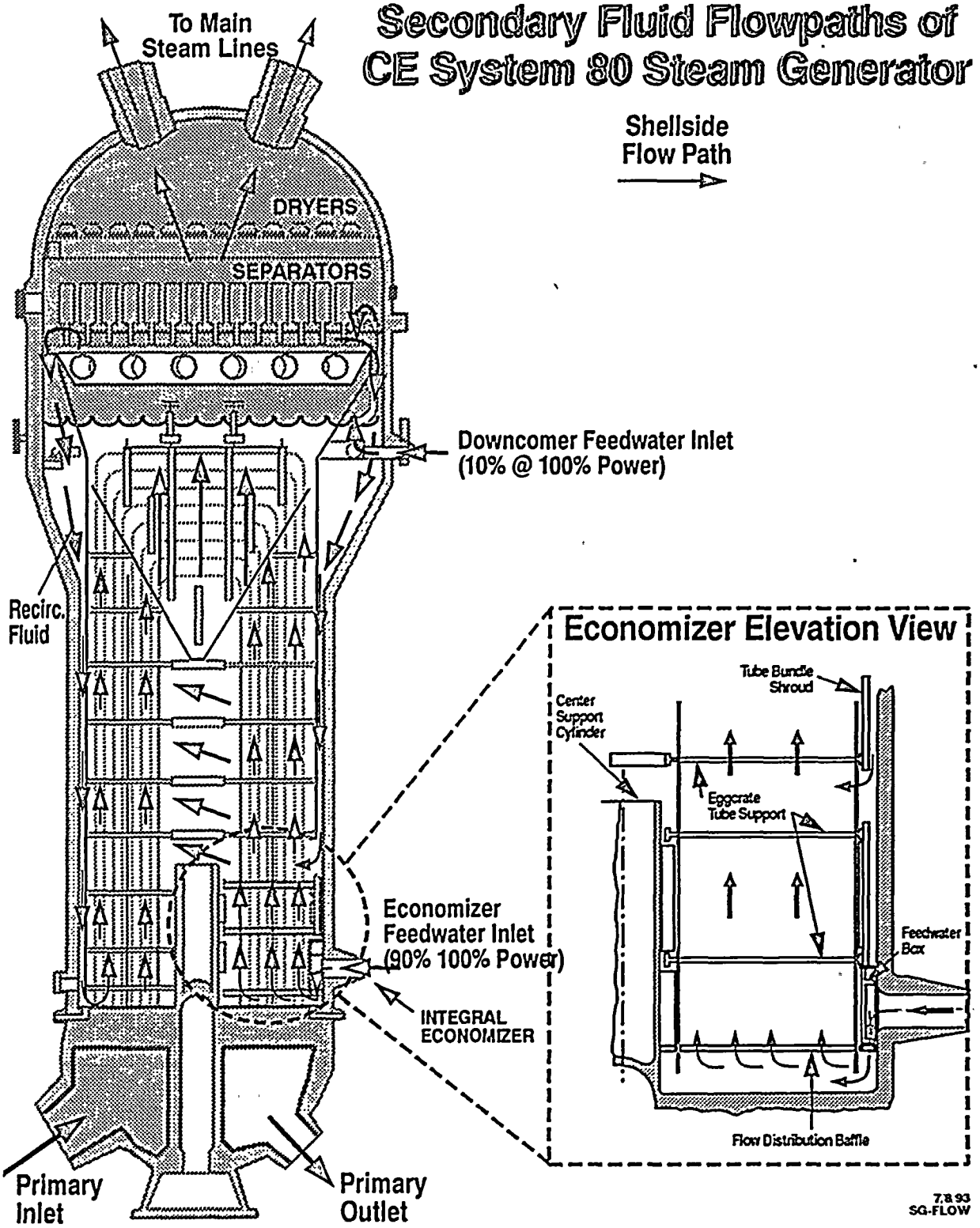
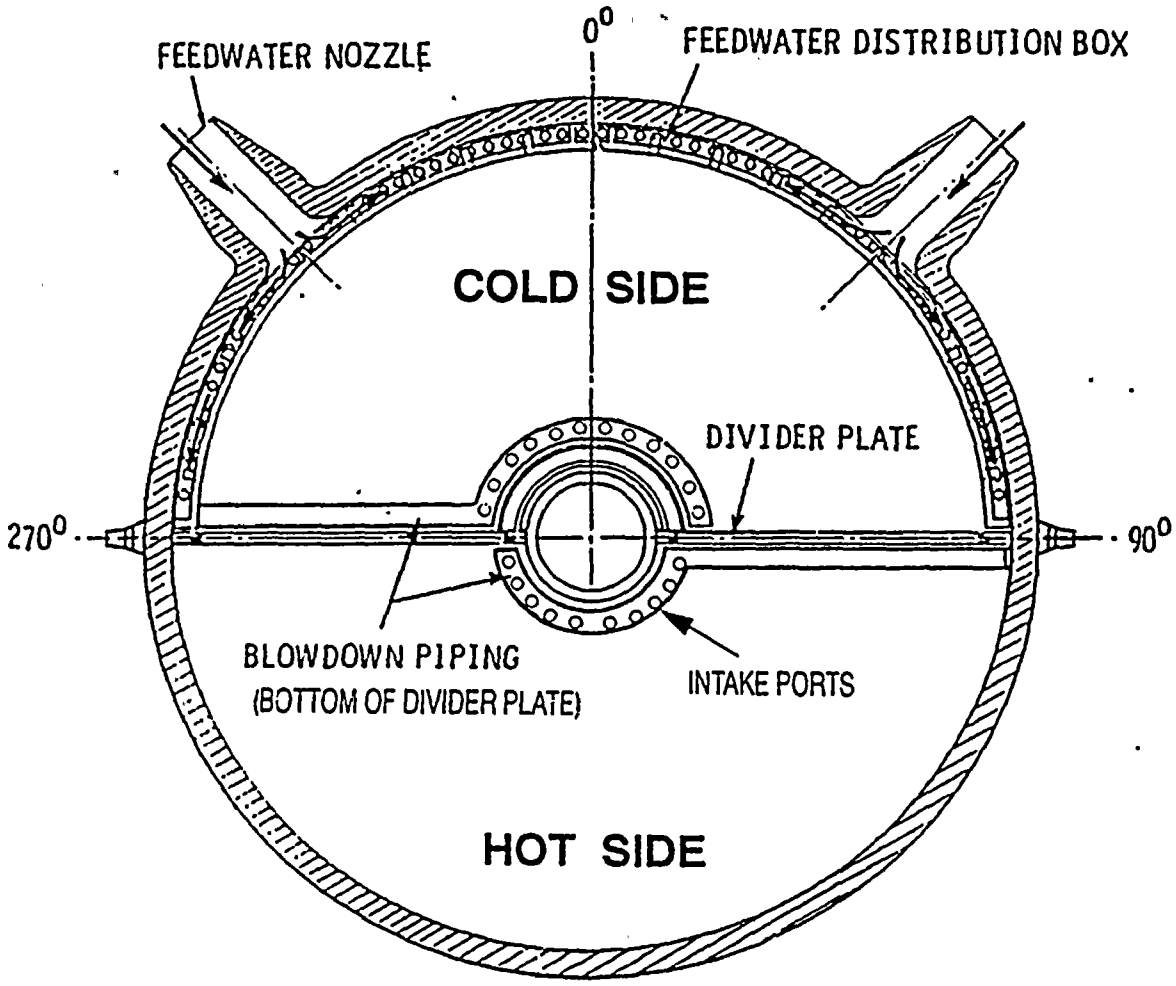


FIGURE III.I.

Schematic Diagram of Blowdown System



Blowdown Piping Arrangement

6 22 93
BLOWDOWN

FIGURE III-j.

Schematic Diagram of Blowdown System

Economizer Region

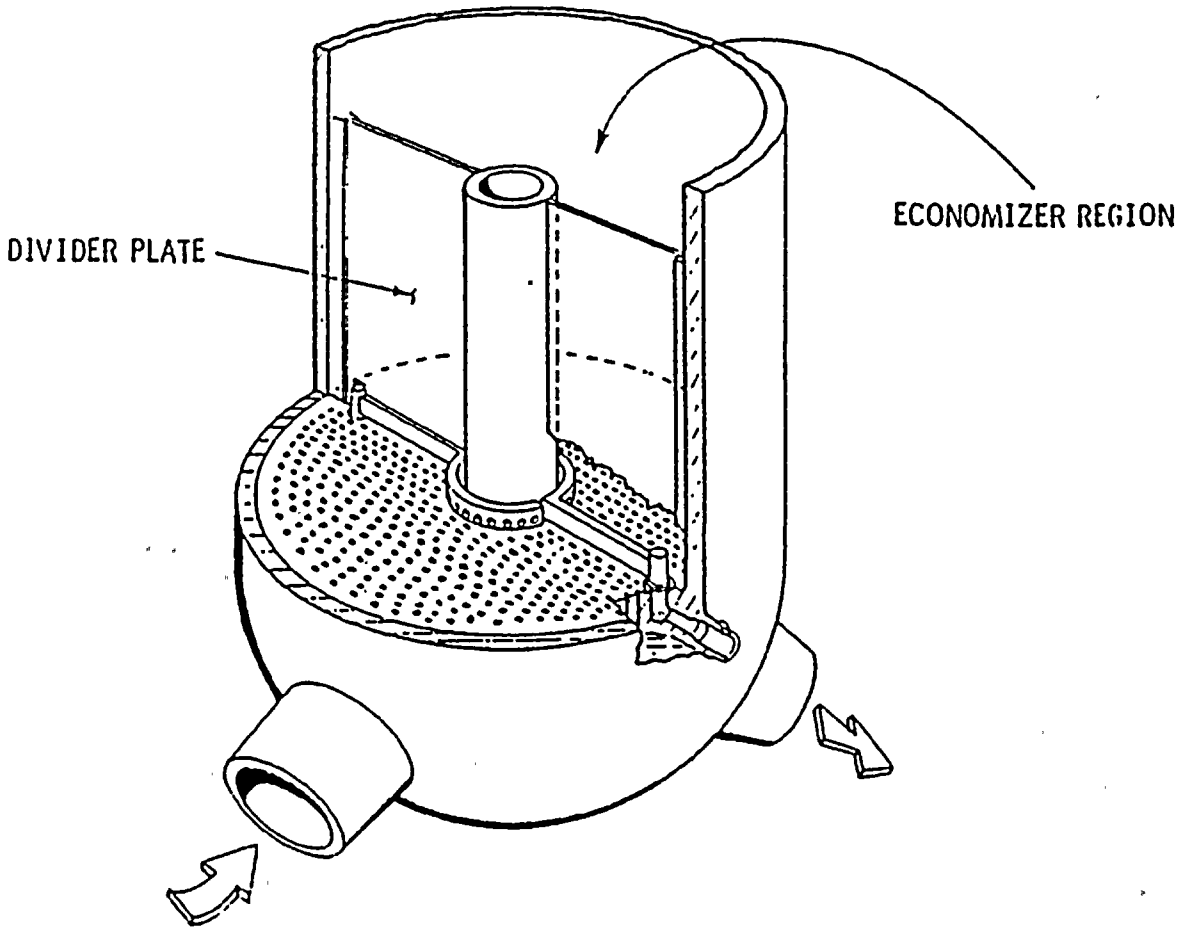


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FIGURE IV-a.

Root Cause Investigation Team - SGTR Event Failure Modes

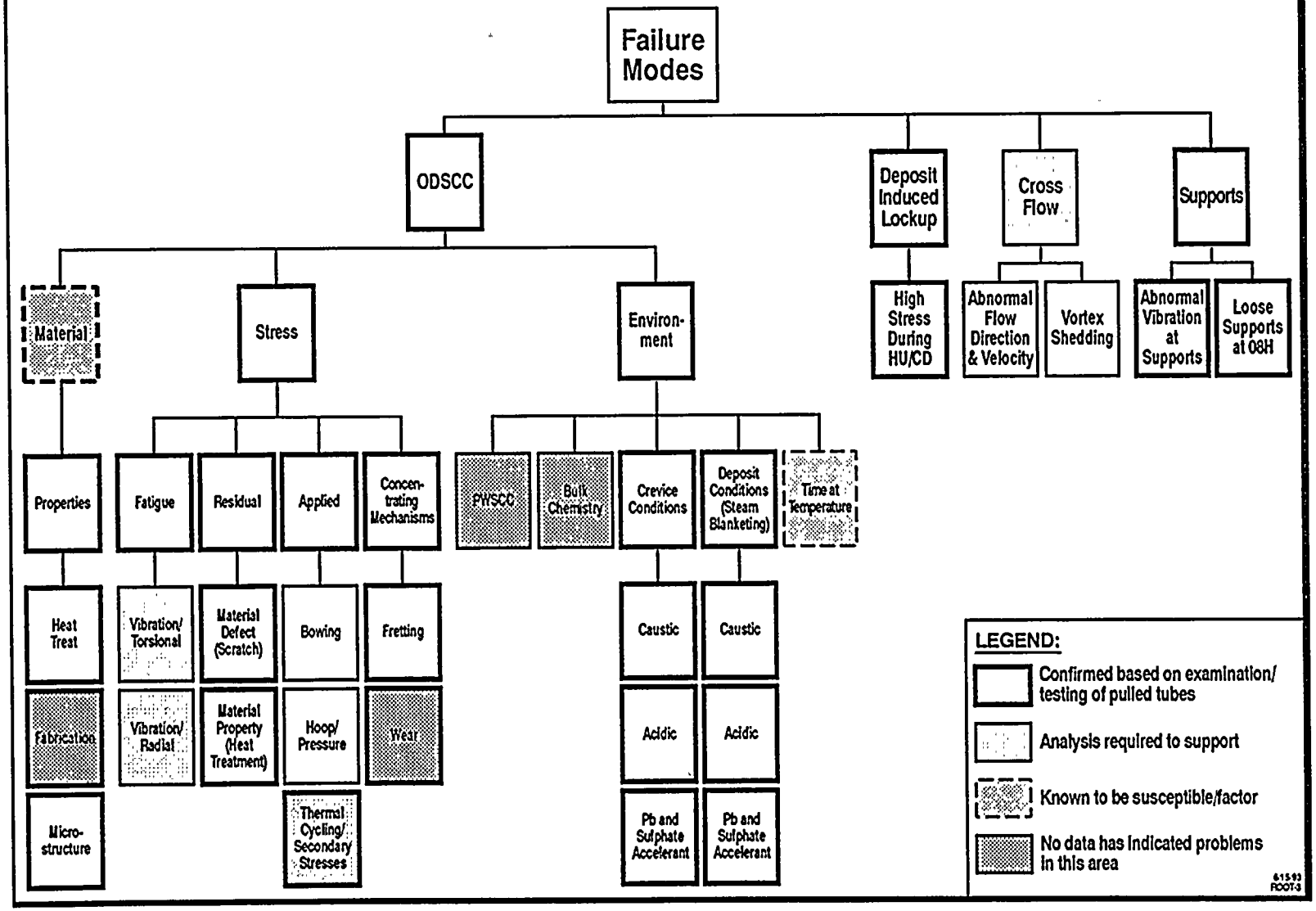

FIGURE IV-b.

Root Cause Investigation Team -- SGTR Event Failure Modes

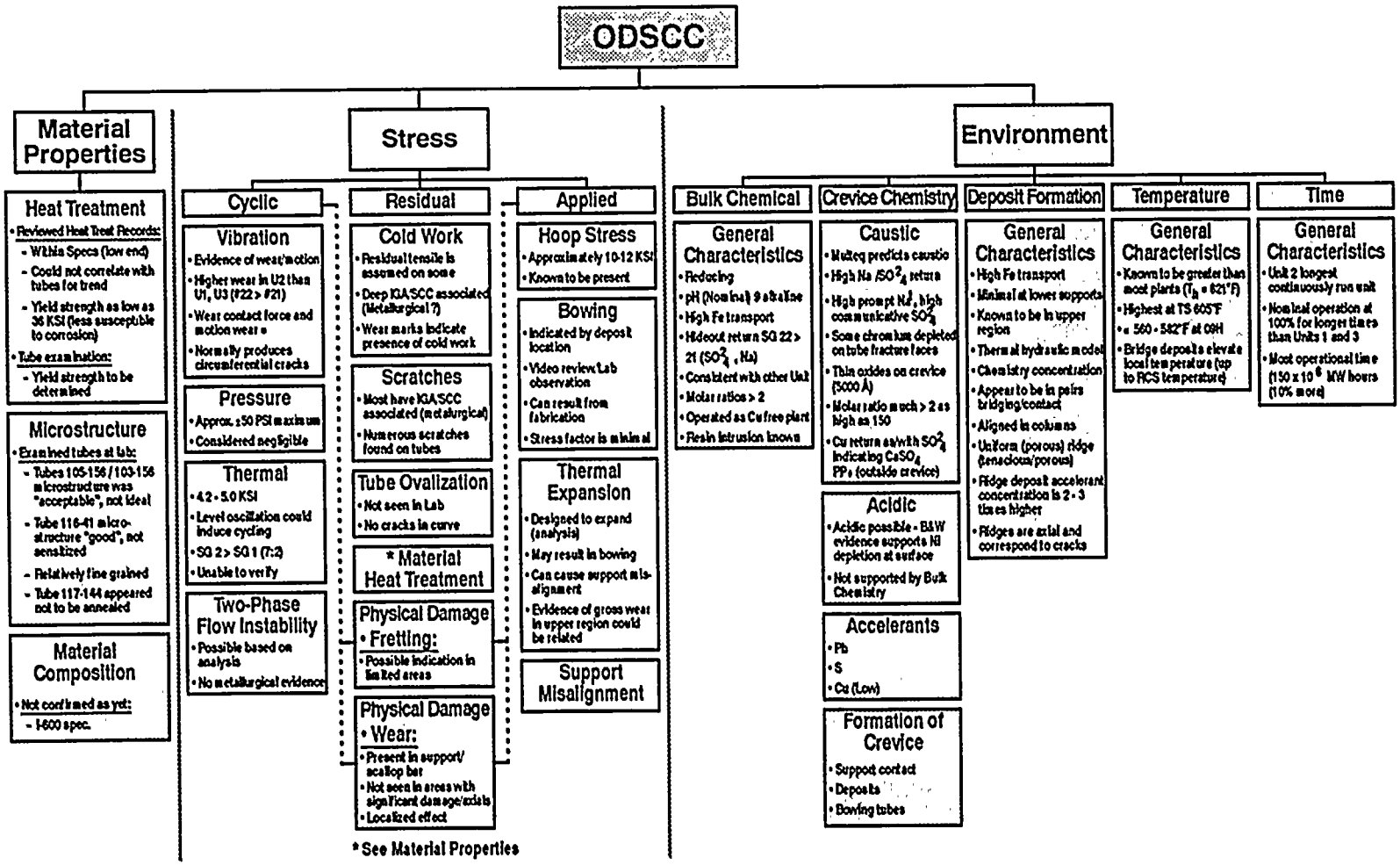

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FIGURE IV-c.

Root Cause Worksheet

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

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FIGURE V-a

HIDEOUT RETURN CHEMISTRY DATA COMPARISONS

PARAMETER	UNIT 1	UNIT 2	UNIT 3	NOTES
SG 1 CHLORIDE	130	65	11	AVERAGE OF ALL PEAK ppb VALUES
SG 1 SULFATE	249	209	231	"
SG 1 SODIUM	232	172	229	"
SG 2 CHLORIDE	91	59	19	"
SG 2 SULFATE	254	228	237	"
SG 2 SODIUM	213	270	231	"
SG 1 RATIO	1.6	2.1	2.7	The average Na/Cl+SO4 ratio of each
SG 2 RATIO	2.0	2.6	3.1	individual shutdown.
SG 1 MR	2.8	2.9	106	The average Na/Cl ratio of each
SG 2 MR	8.1	19.2	89	individual shutdown.
SG 1/2 CHLORIDE	0.9	1.1	0.7	Average SG #1 DIVIDED BY SG #2 data
SG 1/2 SULFATE	1.2	0.9	1.1	from each individual shutdown for
SG 1/2 SODIUM	0.9	0.6	1.0	chloride, sulfate and sodium.

Above data includes:

Unit One:	19 shutdowns July 1987 - February 1993
Unit Two:	19 shutdowns July 1987 - March 1993
Unit Three:	15 shutdowns August 1988 - February 1993

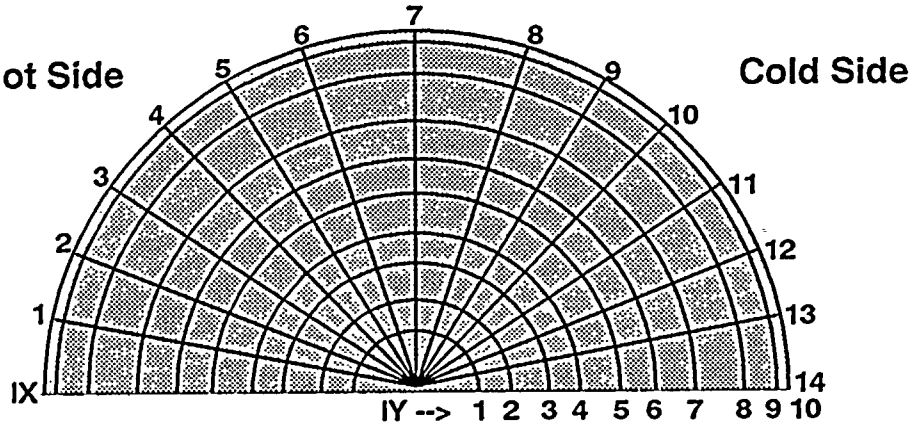
1991 - 1993 HIDEOUT RETURN DATA

PARAMETER	UNIT 1	UNIT 2	UNIT 3
CHLORIDE, average grams	9	2	3
SULFATE, average grams	53	84	37
SODIUM, average grams	42	97	43
LEAD, average grams	2	19	< 1
Na/Cl Ratio, average	7	75	22
MULTEQ, predicted pH *	10.20	10.23	10.35

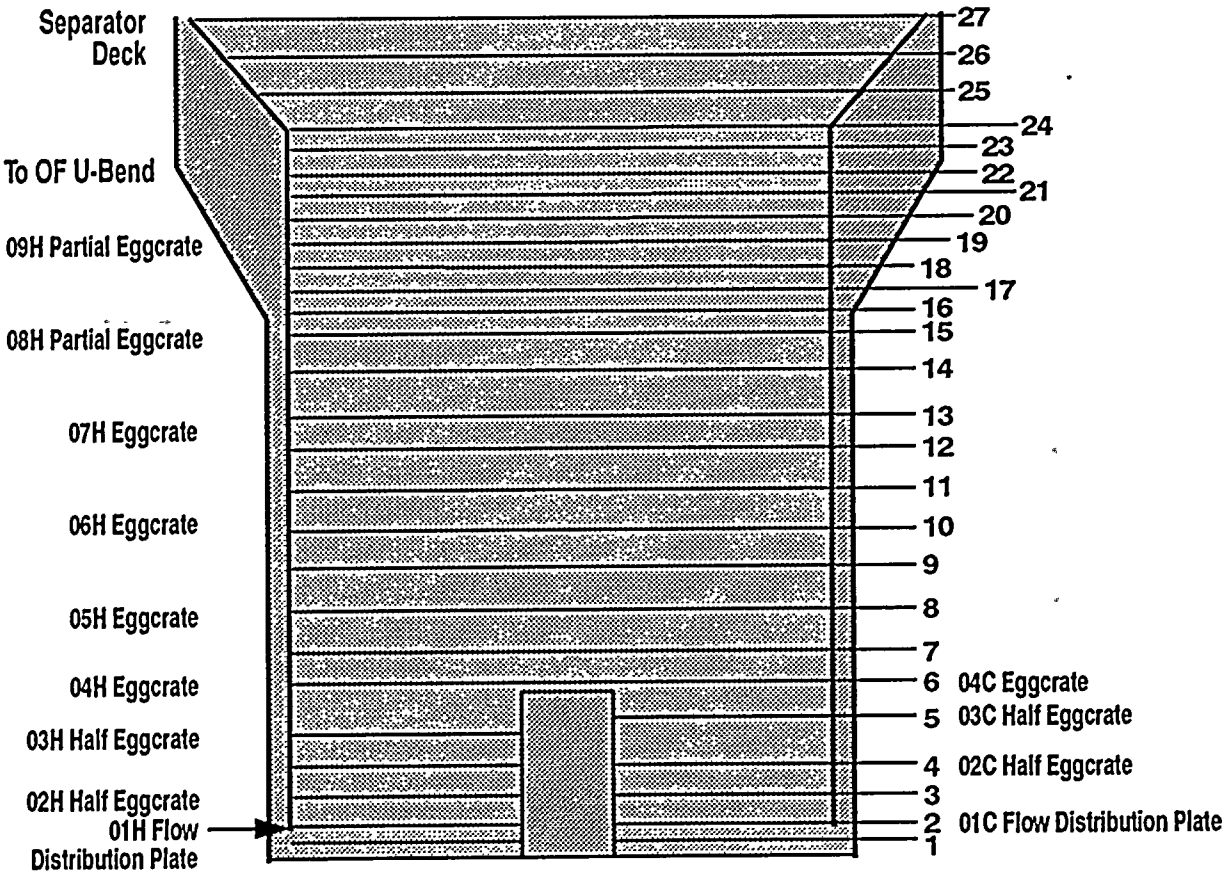
* The above MULTEQ predicted pHs compare prompt hideout return data using the precipitates removed option. If cumulative data is used, and precipitates are not removed, the predicted pH is reduced in some cases to 8.6.

FIGURE VI-a

ATHOS II Model
Palo Verde Steam Generator



Horizontal Nodalization



Vertical Nodalization

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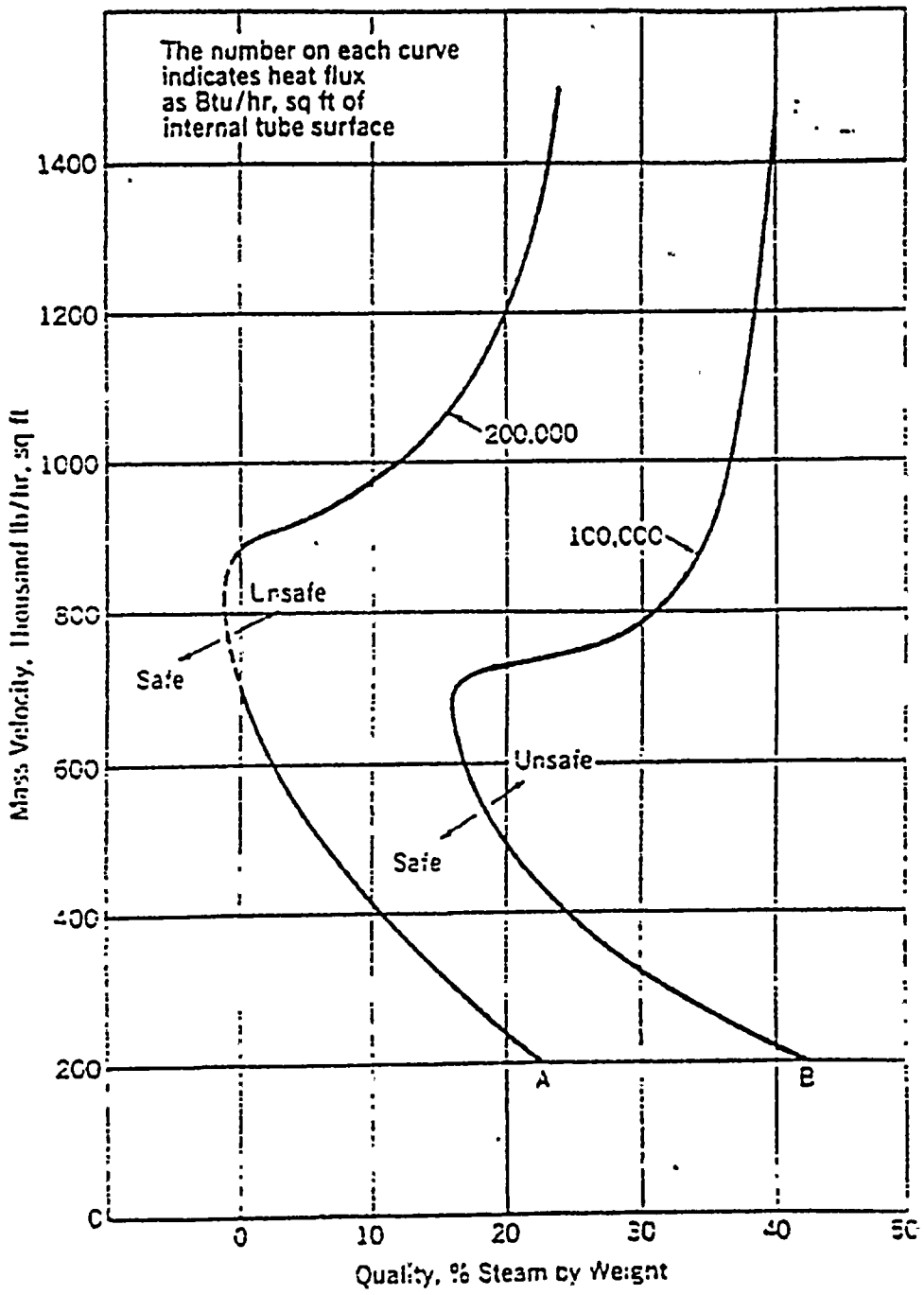
ATHOS-2

FIGURE VI-b

B&W Transition Correlation



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