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October 17, 2002

Mr. Robert L. Clark
Office of Nuclear Regulatory Regulation
U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555-0001

Subject: Supplementary Information Associated with the 2002 Steam Generator Inservice Inspection
Rochester Gas and Electric Corporation
R.E. Ginna Nuclear Power Plant
Docket No. 50-244

Reference: Letter from Robert C. Mecredy (RG&E) to Robert L. Clark (NRC), "Transmittal of Inservice Inspection Report for the Fourth Interval (2000-2009), First Period, Second Outage (2002) - ISI and First Interval (1997-2008), Second Period, First Outage (2002) - IWE/IWL", dated July 9, 2002.

In the above Reference, Rochester Gas & Electric (RG&E) submitted the Ginna Station Inservice Inspection Report as specified in ASME Code Section XI. Subsequent to the submittal, as the result of discussions with the NRC staff, RG&E was asked to provide supplementary information associated with the inspection of the steam generators. The attachments to this letter provide the requested information.

If you should have any questions regarding this submittal, please contact Mr. Thomas Harding, 585-771-3384.

Very truly yours,

Robert C. Mecredy

Robert C. Mecredy
Vice President
Nuclear Operations Group

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Attachments:

I. Previous Steam Generator Inspection History (Design Analysis DA-ME-2002-020, Steam Generator Degradation Assessment - 2002 Outage)
II. 2002 Steam Generator Inspection Summary (excerpt from the Westinghouse Eddy Current Examination Report)
III. Steam Generator Tube Sheet Maps
IV. Steam Generator Tube Support Numbering Figure

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Attachment I

R.E. Ginna Nuclear Power Plant

Previous Steam Generator Inspection History

Steam Generator Degradation Assessment
2002 Outage

Ginna Station

Rochester Gas and Electric Corporation
1503 Lake Road
Ontario, New York

DA-ME-2001-020

Revision 1

ETSS References in this Degradation Assessment:

96004.2	**96008.1**	**96010.1**	**96511.2**	**96910.1**	**96911.1**
20510.1	**20511.1**	**21409.1**	**21410.1**		

Prepared By: ______________________ Date: 7/23/02
Assigned Engineer

Reviewed By: ______________________ Date: 7/24/02
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Reviewed By: ______________________ Date: 7/24/02
Corporate NDE Coordinator
(Review Requirement per IP-SGP-2)

Revision Status Sheet

Revision Number	Affected Sections	Description of Revision
0	All	Initial Release
1	1.4, 2.5	Revision to Purpose and Conclusion sections for revised degradation assessment.
	4.42, 4.43, 4.44, 7.1.1, 9.2.2	Additional information from Seabrook cracking and Darlington fretting.
	10.2.5	Corrected error in MBM RPC scope from 1999 outage.
	10.4.1 (e)	ETSS reference typographical error corrected.
	10.4.1 (g)	Added new information from OPG Darlington and discussed impact. Included discussion regarding tubes inspected in 1999.
	10.6.5 (a)	Corrected error in MBM RPC scope planned for 2002 outage.

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1 Purpose / Scope

1.1 This pre-outage degradation assessment is being performed in preparation for the 2002 Ginna Station refueling outage steam generator tube in-service inspection and tube integrity assessment.

1.2 This design analysis will document active and potential degradation mechanisms in the Ginna replacement steam generators, including secondary-side degradation mechanisms.

1.3 For each tube degradation mechanism identified, the following will be identified:

- ETSS to be used for detection and sizing (if applicable)
- structural limit, condition monitoring (tube integrity) limit, and operational assessment (repair) limit.

1.4 Revision 1 of this degradation assessment corrects several minor errors in Revision 0 and adds additional information based on recent industry experience to justify the length of the upcoming operating interval. Revision 1 was completed following the 2002 inspection, in which no degradation was found in the Ginna steam generators.

2 Conclusions

2.1 The results of this degradation assessment are summarized in Table 1.

2.2 Wear, particularly at U-bend supports, is the only degradation mechanism that is expected to be seen during the 2002 refueling outage. This is based on a review of industry experience with Alloy 690TT steam generators, including Babcock & Wilcox replacement steam generators.

2.3 Although wear is the only mechanism anticipated, the ECT program scope has been conservatively set to detect corrosion-related mechanisms that have not yet been seen in Alloy 690TT steam generators with longer service at higher hot-leg temperatures than Ginna. These include expansion transition cracking (PWSCC, ODSCC), cracking under sludge pile deposits, inner-row U-bend cracking, and degradation at MBM sites.

2.4 The "localized" u-bend wear phenomenon seen at St. Lucie 1 and McGuire 1 necessitates an additional expansion criterion beyond what is specified in the EPRI *PWR Steam Generator Examination Guidelines*. This mechanism, which hasn't been found at Ginna during previous inspections, involves wear localized to one column, and possibly an adjacent column. Almost every tube that is bobbin inspected in 2002 will be next to a column that is not inspected; in the event that u-bend wear is found in a tube, the neighboring uninspected column will be added to the inspection plan.

2.5 There are no changes to the operational assessment limits as a result of the new experience since Revision 0. The next inspection is planned for the spring 2005 refueling outage.

3 Design Inputs

3.1 ITS Section 5.5.8 refers the Steam Generator Tube Inspection Program in the ISI program. This program (which will be replaced by the Steam Generator Program mandated by ND-SGP if the anticipated regulatory changes occur) requires that tubes with imperfections greater than 40% through wall be repaired by plugging or sleeving. No Operational Assessment limit may exceed this value.

3.2 Tube outside diameter is 0.749 ± 0.001 inches (Reference 4.9). Therefore the nominal tube OD of 0.75 inches will be used to determine integrity assessment limits.

3.3 Tube wall thickness is 0.044 ± 0.001 inches (Reference 4.9). Therefore the nominal tube wall thickness of 0.043 inches will be used to determine integrity assessment limits.

3.4 Tube material is Alloy 690TT (Thermally Treated). The following minimum strengths at 650°F are interpolated from the data in Table 3-1 of Reference 4.10:

3.4.1 Ultimate Tensile Strength (S_u) at 650°F is 80 ksi minimum.

3.4.2 Yield Strength (S_y) at 650°F is 35.2 ksi minimum.

3.5 Normal primary (RCS) pressure is 2235 psig (Reference 4.37)

3.6 Primary-side design pressure is 2485 psig (Reference 4.10). This equals the setpoint of the pressurizer safety valves (Reference 4.37).

3.7 Normal operating 100% power steam generator secondary pressures are ~740 psig based on a review of PPCS data for the current cycle. A value of 735 psig will be used in this analysis to determine the normal operating differential pressure.

3.8 Secondary-side design pressure is 1085 psig (Reference 4.10). This equals the setpoint of the first two main steam safety valves (Reference 4.36).

3.9 The maximum RCS pressure of 2485 psig will be used as the limiting accident differential pressure in this analysis.

3.10 Using the normal RCS operating pressure of 2235 psig, and the steam generator secondary pressure of 735 psig, the normal operating differential pressure is therefore 1500 psig.

3.11 The accident-induced leakage limit is 1.0 gpm/SG. Ginna does not have an analysis of record for steam line break doses. A 1.0 gpm/SG value is consistent with preliminary analyses (section 5.8 in Reference 4.39) completed as part of the Ginna Dose Reassessment Project, and was also the value assumed by the NRC for an evaluation done during the Systematic Evaluation Program in 1982.

4 References

4.1 EPRI TR-107621-R1, *Steam Generator Integrity Assessment Guidelines*.

4.2 *Steam Generator Degradation Specific Management Flaw Handbook*, EPRI, Palo Alto, CA: 2001. 1001191. (Controlled Copy D-FH191-1030-2; this is the revised copy of this report that was re-issued without revision to correct various errors).

4.3 Behravesh, Mohamad, *ISI Guidelines Support of SG Tube Integrity Assessments*, paper from EPRI SGMP website.

4.4 Harris, D.H., *Appendix G Generic NDE Information for Condition Monitoring and Operational Assessments*, updated 6/1/99, paper from EPRI SGMP website.

4.5 EPRI TR-107569-R5, *PWR Steam Generator Examination Guidelines*.

4.6 EPRI TR-107620-R1, *Steam Generator In Situ Pressure Test Guidelines*.

4.7 IP-SGP-2, Steam Generator Tube Integrity Assessment.

4.8 IP-SGP-3, Steam Generator Tube Inspections.

4.9 Replacement Steam Generator History Dockets.

4.10 Babcock & Wilcox Report 222-7705-SR-7 Revision 1, *Replacement Steam Generators - Tube Stress Analysis Report*.

4.11 Babcock & Wilcox Report 222-7705-FIV-2 Revision 1, *Tube Wear Analysis Report*.

4.12 Babcock & Wilcox Report BWI-TR-95-05 Revision 1, *Tube-to-Tubesheet Joint Qualification: Program Summary*.

4.13 Babcock & Wilcox Report BWI-TR-95-25 Revision 0, *Experimental/Analytical Residual Stress and CERT Evaluations of Hydraulic Expansions Beyond the Tubesheet Secondary Face*.

4.14 ABB CENP Report # 99-TR-FSW-004 Revision 0, *Pre-Outage Degradation Assessment Report for Rochester Gas and Electric Company, R.E. Ginna Station*, dated 3/9/99.

4.15 ABB CENP Report # 99-TR-FSW-008 Revision 0, *End of Cycle 27 Condition Monitoring and Operational Assessment for Cycles 28 & 29 Final Report*, dated 7/8/99.

4.16 Babcock & Wilcox Nuclear Steam Generator Information Bulletin DTF-61.1.00003, *U-Bend Tube Spacing*, dated August 28, 1997.

4.17 Babcock & Wilcox Nuclear Steam Generator Information Bulletin DTF-61.1.00004, *U-Bend Tube Fretting, Darlington NGS*, dated March 6, 1998.

4.18 Babcock & Wilcox Nuclear Steam Generator Information Bulletin DTF-61.1.00006, *McGuire Units 1 & 2 U-Bend Tube Fretting*, dated February 22, 2000.

4.19 Babcock & Wilcox Nuclear Steam Generator Information Bulletin DTF-61.1.00007, *St. Lucie 1 RSG, U-Bend Tube Fretting*, dated February 23, 2000.

4.20 EdF Utility Experience Report, presented at SGMP Technical Advisory Group Meeting, 12/11-13/2001 in New Orleans, by Francis Nordmann.

4.21 ETSS # 96004.2 Revision 7 (Wear at Tube Supports, Bobbin Coil) dated 2/01.

4.22 ETSS # 96008.1 Revision 10 (Axial ODSCC at Eggcrates and/or Sludge Pile, Bobbin Coil) dated 3/02.

4.23 ETSS # 96010.1 Revision 4 (Small Volume MBMs in Tube Freespan, Bobbin Coil) dated 4/01.

4.24 ETSS # 96511.2 Revision 10 (Circumferential and Axial PWSCC in Low-Row U-bends, +Point Coil) dated 1/01.

4.25 ETSS # 96910.1 Revision 5 (Mechanically-Induced Wear at Broached Tube Support Plates, +Point Coil) dated 3/02.

4.26 ETSS # 96911.1 Revision 5 (Mechanically-Induced Wear at Broached Tube Support Plates, Pancake Coil) dated 3/02.

4.27 ETSS # 20510.1 Revision 2 (Circumferential PWSCC at Expansion Transitions, +Point Coil) dated 3/02.

4.28 ETSS # 20511.1 Revision 2 (Axial PWSCC at Expansion Transitions, +Point Coil) dated 3/02.

4.29 ETSS # 21409.1 Revision 0 (Axial ODSCC at Support Structures, Freespan Regions, Sludge Pile, and Tubesheet Crevice) dated 3/02.

4.30 ETSS # 21410.1 Revision 0 (Circumferential ODSCC at Expansion Transitions, +Point Coil) dated 3/02.

4.31 Letter, Mecredy (RGE) to Vissing (USNRC), *Subject: Response to NRC Generic Letter 97-06 (Degradation of Steam Generator Internals)*, dated 3/30/98.

4.32 ACTION Report 97-1429, *Potential Steam Generator Fabrication Deficiencies*.

4.33 VTD-B0015-4002 Revision 000, *Replacement Steam Generator Operating and Maintenance Manual*.

4.34 Report, *1997 Refueling Outage, Replacement Steam Generator Secondary Internals Inspection Report*, copy attached to Reference 4.31.

4.35 NRC Information Notice 2001-16, *Recent Foreign and Domestic Experience with Degradation of Steam Generator Tubes and Internals.*

4.36 UFSAR Revision 16, Table 10.1-1, *Steam and Power Conversion System Component Design Parameters.*

4.37 UFSAR Revision 16, Table 5.1-1, *Reactor Coolant System Pressure Settings.*

4.38 Telecon, G. Verdin (RGE) to J. Albert (Babcock & Wilcox RSG Warranty Engineer), 3/4/02.

4.39 DA-NS-2002-007 Revision 0 (Preliminary), *Main Steam Line Break Offsite and Control Room Doses.*

4.40 Babcock & Wilcox Material Specification TS-8044 Revision 04, *Technical Specification for Nickel-Chromium-Iron (Alloy 690) Nuclear Steam Generator Quality Tubing.*

4.41 EPRI TR-103824s-V1R1, *Steam Generator Reference Book.*

4.42 *Steam Generator Tube Fretting Experience*, Schneider and Fluit (B&W Canada), presented at 2002 Canadian Nuclear Society Steam Generator Conference, 5/02.

4.43 *Steam Generator Tube Fretting - Darlington NGS Experience,* Mirzai and Paras (Ontario Power Generation), presented at 2002 Canadian Nuclear Society Steam Generator Conference, 5/02.

4.44 NRC Information Notice 2002-21, *Axial Outside-Diameter Cracking Affecting Thermally Treated Alloy 600 Steam Generator Tubing.*

5 Assumptions

5.1 Operational assessment limits in this degradation assessment assume that two cycles of operation will be completed before the next inspection in Spring 2005. A conservative run time of 3.0 EFPY will be used to calculate OA limits.

5.2 Based on text in section 2.2.2 of Reference 4.2, it will be assumed that the minimum tube wall thickness to prevent collapse during a LOCA will always be less that the tube thickness required to prevent burst during a steam or feedwater line break. No effort will be spent analyzing tube integrity for LOCA conditions where secondary pressure exceeds the RCS pressure.

5.3 ASME Code minimum properties are used for tubing. These are conservative minimums, so no material strength uncertainty is applied to structural or leakage limit calculations in this degradation assessment.

6 Computer Codes

6.1 MathCAD was used to perform calculations for this report. It is not qualified per IP-SQA-1. The Independent Reviewer must verify calculations for correctness.

7 Steam Generator Degradation Mechanisms

7.1 Stress Corrosion Cracking

Stress corrosion cracking, regardless of whether ID or OD initiated, has three causal factors:

- Susceptible material condition
- Aggressive environment
- Tensile stress greater than the threshold stress required for a particular environment

Each potential SCC mechanism can be evaluated on the basis of these three causal factors.

7.1.1 Alloy 690TT and Alloy 600MA

A major reason for the development of Alloy 690TT was the tendency of Alloy 600MA to crack in relatively pure water such as that of the primary coolant in PWRs. Primary-Water Stress Corrosion Cracking (PWSCC) has occurred in Alloy 600MA tubes in many PWR Steam Generators.

Many laboratory tests in high-temperature simulated primary water confirm that Alloy 600MA, in certain metallurgical conditions, is very susceptible to PWSCC. Many of these tests have demonstrated that Alloy 690TT is very resistant to PWSCC, and generally will not crack regardless of metallurgical condition or stress level. On the rare occurrences where PWSCC of Alloy 690TT has occurred, the tests involved material that had mechanical properties outside the bounds of current procurement specifications as would have been expected with improper heat treatment. Such material conditions are not expected at Ginna.

Alloy 600MA is very susceptible to stress corrosion cracking in caustic environments, such as those that may develop on the secondary side in crevices as a result of the concentration of low levels of bulk water contaminants. This typically occurs in plants using fresh water lakes or rivers as sources of condenser cooling water or in plants that are emitting sodium species in condensate polisher effluent. Severe SCC has been reported in numerous steam generators under what is believed to have been caustic crevice conditions. Alloy 690TT has been superior to Alloy 600MA in caustic environments in the laboratory, although SCC has occurred on rare occasions. To date there have not been any occurrences of caustic SCC in operating plants with Alloy 690TT.

In the laboratory Alloy 690TT has also been superior to Alloy 600MA in acidic environments, which can occur at sea water sites and sites with cooling towers, as a result of contaminant concentration. Concentration of acid sulfates or chlorides provides this condition. Some investigators report that Alloy 690TT is immune to SCC in acidic sulfate and chloride environments but could be susceptible to pitting or general corrosion (wastage). If copper or its oxides are present, Alloy 690TT becomes very susceptible to SCC in acidic sulfate environments.

There are other contaminants that could cause corrosion degradation of Alloy 690TT steam generator tubes. Foremost among these is lead, which will cause SCC in Alloy 690TT and 600MA, regardless of the pH of the solution.

In summary, Alloy 690TT is clearly superior to Alloy 600MA with respect to stress corrosion cracking.

Additional support for this conclusion is provided by the service experience of several replacement steam generators with Alloy 600TT (Thermally-Treated) tubes, including Surrey 1/2 (1981/1980), Turkey Point 3/4 (1982/1983), Point Beach 1 (1984) and H. B. Robinson (1984). Laboratory testing has demonstrated that the SCC resistance of Alloy 600TT is between Alloy 600MA and Alloy 690TT.

Recent cracks found at Seabrook station (Alloy 600TT tubing) during their spring 2002 (~10 EFPY service) outage may be the first instance of cracking of this alloy in domestic units. There are unusual aspects to this cracking however (cold leg cracks, limited extent) which call into question whether this is typical ODSCC. Although this event is clearly very significant, it does not impact the timing of the next Ginna inspection since:

- Ginna has Alloy 690TT tubing which has been demonstrated to be better than 600TT in the laboratory.
- Ginna will have ~8 EFPY at the next inspection, with service at a much lower T_{hot} than Seabrook.

Any generic issues arising out of the yet-to-be completed Seabrook root cause evaluation will be tracked through the Ginna Station corrective action program.

7.1.2 Aggressive Environment

Steam generator secondary-side environments can be quite aggressive since boiling in crevices under deposits, at tube supports, and at the tubesheet can concentrate contaminants in the bulk water creating highly acidic or caustic localized environments. Stress corrosion cracking will typically occur in these areas.

7.1.3 Tensile Stresses

Large tensile stresses can occur in steam generators as a result of operating and residual stresses from fabrication processes (tube bending, tubesheet expansion, etc.). Denting, discussed in section 7.6, can also result in large residual stresses.

7.2 Intergranular Attack (IGA)

IGA has occurred in Alloy 600 tubes in tubesheet crevices, at the top of tubesheet locations and at freespan locations. IGA can develop in Alloy 600 as a result of caustic environments, caustic environments with sulfur species, and acidic sulfate environments (not present at Ginna). It differs from SCC in that there is an absence of a stress dependency and the corrosion is volumetric (all grain boundaries in a area are attacked). Again, the use of Alloy 690TT will result in a much reduced potential for IGA.

7.3 Pitting

Pitting occurs at a low pH (acidic conditions), generally in the presence of chlorides but also possibly with sulfates. The presence of copper oxides from the balance of plant components (BOP) such as condensers, feed water heaters, etc. greatly accelerate pitting corrosion. Alloy 690TT may be somewhat more resistant to pitting than Alloy 600MA.

7.4 Wastage

Wastage is a general corrosion phenomenon that occurs at very low pH conditions usually caused by concentration of acidic phosphates or sulfates in high heat flux areas.

7.5 Wear (Fretting)

Flow-induced vibration of tubes against supports or anti-vibration bar type supports has resulted in wear type defects in many steam generators, including B&W steam generators with features similar to the Ginna RSGs.

A second source of wear damage is caused by flow-induced vibration of loose parts against tubes.

7.6 Denting at Tube Supports

Denting of SG tubes as a result of carbon steel tube support corrosion was a major cause of repairs in the 1980s at US PWRs. The accelerated corrosion of carbon steel necessary to cause denting results from the development of acid conditions in tube support crevices as a result of the concentration of chlorides present in the bulk secondary water as a result of condenser in-leakage. Copper oxides that enter the SGs as a result of BOP component corrosion by air in-leakage exacerbates this corrosion.

8 Degradation Experience in Steam Generators with Alloy 690TT Tubing

8.1 Subject Population

From an EPRI Steam Generator Degradation Database (SGDD) query on 3/5/02, there are currently 57 operating PWRs with Alloy 690TT steam generators. Ten (10) are original equipment with the remainder (47) being replacement steam generators.

The earliest replacement steam generators to use Alloy 690TT were D.C. Cook 2 (3/1/89, 5.9 EFPY), Indian Point 3 (6/1/89, 7.0 EFPY), and Ringhals 2 (8/1/89, 8.0 EFPY). All EFPY values are given for the last inspection.

8.2 Degradation Observed

The SGDD was queried for tube repairs by year for all steam generators with Alloy 690TT tube material. After eliminating all pre-service plugging and obvious duplicate errors (where a plant listed the same repair in a SG replacement year with 0.0 EFPY and another significantly higher EFPY), it was found that tubes were plugged for:

- Wear
- Pressure-pulse cleaning damage (or to prevent it)
- Tubes found unexpanded
- Excessive ECT noise
- Preventive reasons such as proximity to baffle plate edges

Several "OTHER" causes were given for French PWR plants. From the endnote on page 8 of Reference 4.20, the "OTHER" code is given for "magnetic anomalies, rolling anomalies, various causes".

Based on this review, it can be seen that there has been no corrosion-related degradation in steam generators with Alloy 690TT tubing to date. This includes steam generators that have been in service longer than Ginna with higher hot leg temperatures.

9 Degradation Experience in Babcock & Wilcox "Advanced Series" Steam Generators

9.1 Subject Population

Babcock & Wilcox has designed and manufactured several generations of recirculating steam generators for CANDU and PWR plants. The most recent steam generators include lattice grid tube supports, fan-bar U-bend supports, and curved-arm primary/modular secondary cyclone separators. The tubing in these steam generators is Alloy 690TT (PWR RSGs) and Alloy 800 (CANDU SGs).

The "lead" plant for this "advanced series" of steam generator was Darlington Nuclear Generating Station Units 1/2/3/4, with four steam generators per reactor unit. Subsequent CANDU steam generators at Wolsong 2/3/4 (Korea), and Cernavoda 1 (Romania) are also included in this category, although very limited information is available on these. All are Alloy 800 units.

PWR replacement steam generators at Millstone 2, Ginna, Catawba 1, McGuire 1/2, Byron 1, Braidwood 1, Cook 1, and St. Lucie 1 also fall in the "advanced series" category and have Alloy 690TT tubing.

9.2 Degradation Observed

In-service degradation has been observed in the advanced series B&W steam generators, as documented in References 4.16, 4.17, 4.18, and 4.19. This degradation is all wear-related, mostly at U-bend supports. A more detailed discussion is included below.

9.2.1 U-Bend Tube Proximity Issue

Babcock & Wilcox issued an information bulletin (Reference 4.16) in 1997 indicating a potential issue relating to the way in which their steam generators had been tubed. It is important to recognize that the U-bend tube proximity issue is a precursor to potential wear degradation, and not an actual degradation mode itself.

The U-bend support structure in B&W steam generators is supported at a large number (several 100) of locations by J-tabs, which rest on the tubes. The J-tabs are inserted against the tube then welded to the arch-bar/clamping bar assembly. This process is done with the steam generator in a horizontal position at the fabrication plant.

Prior to discovery of the proximity issue, no special attention was paid to positioning the outermost tubes before setting and welding the J-tabs. If a tube was not properly positioned (i.e. not spaced consistently to maintain design clearances relative to the tube below it) prior to welding the J-tab, then the weight of the U-bend support may distort the tube shape when it is vertical. The end result is that the outermost tube in a column may fret against the tube below it.

It is important to note that the proximity of one tube to the tube below it may differ between the cold (inspection) condition and the normal operating temperature.

9.2.2 U-Bend Fan Bar and Lattice Grid "Typical" Wear

"Typical" wear refers to indications that would result from classical tube-to-bar wear resulting in either uniform or tapered wear on the tube. Degradation of this type at Darlington, McGuire 1/2, and St. Lucie 1 is discussed in References 4.17, 4.18, and 4.19 respectively.

Additional information on fretting wear in B&W recirculating steam generators can be found in References 4.42 and 4.43.

This type of wear is a result of large tube-to-support clearances. The most-affected units at Darlington have larger clearances by design than the newer RSGs. In an analysis in Reference 4.11, B&W predicted that the tube wear rate at Darlington would be twice the rate that would be expected at Ginna. This was based on a relative comparison of the tube and support materials, thermal-hydraulic conditions, and nominal tube-to-support clearances.

Although Ginna is predicted to have a generally lower wear rate than Darlington (approximately 50% lower), actual wear indications seen at other plants tend to be random (other than those discussed in 9.2.3). The impact of random tolerance variations cannot be discounted based on the results of the analysis in Reference 4.11.

9.2.3 U-Bend Fan Bar "Typical" Wear (Localized)

Localized typical wear has been observed in the St. Lucie 1 replacement steam generators as discussed in Reference 4.19. A similar mechanism was identified at McGuire 1 as discussed in Reference 4.18. This mechanism is not fundamentally different from that in section 9.2.2 but is localized to particular tube columns. It is theorized that the localized effect is due to arch-bar distortion, instead of a more random manufacturing tolerance issue.

9.2.4 U-Bend Fan Bar "Atypical" Wear

"Atypical" wear refers to pit-like indications found at flat-bar supports in the McGuire 1/2 and St. Lucie 1 replacement steam generators. These indications are believed to be the result of asperities on the flat bars and are attributed to fabrication deficiencies. This type of wear is discussed further in Reference 4.18 and 4.19.

10 Ginna-Specific Degradation Assessment

10.1 Ginna Experience

The Ginna replacement steam generators were installed during the spring 1996 (end of cycle 25) refueling outage. The plant commenced operation with the RSGs in June 1996.

The first in-service ECT inspection of the replacement steam generators occurred during the fall 1997 outage (end of cycle 26). The scope included full-length bobbin on 100% of tubes, 10% RPC on hot-leg TTS expansion transitions, bobbin screening on peripheral tubes for tube proximity, RPC on peripheral tubes which screened as potential proximity sites, plus several diagnostic tests. No degradation was found.

Secondary-side visual inspections were carried out on both RSGs during the 1997 refueling outage. These inspections formed the basis for the response to NRC Generic Letter 97-06 (Reference 4.31). No degradation of any kind was found during these visual inspections.

The second in-service ECT inspection of the RSGs occurred during the spring 1999 outage (end of cycle 27). The scope included full-length bobbin on 50% of tubes, 20% RPC on hot-leg TTS expansion transitions, tube proximity screening using improved low-frequency bobbin technique, RPC on known and suspected proximity sites, and several diagnostic tests. Again, no degradation was found.

Based on the results of a successful multi-cycle operational assessment (Reference 4.15) and absence of any active damage mechanisms, it was decided that no inspections would be carried out during the Fall 2000 outage (end of cycle 28). This is allowed by the EPRI PWR *Steam Generator Examination Guidelines* (Reference 4.5).

This degradation assessment precedes the inspections planned for the Spring 2002 refueling outage (end of Cycle 29).

10.2 Ginna RSG Anomalies

An understanding of anomalous conditions in the Ginna RSGs is necessary prior to assessing potential and relevant degradation mechanisms.

10.2.1 Plugged Tubes

One tube per RSG was preventatively plugged prior to service using welded plugs. The plug welds were inspected visually and with liquid penetrant.

In SGA, one tube (Row 52, Column 14) was plugged due to wall loss greater than 15% between the first and second lattice grids on the hot leg side (Reference 4.33, Appendix X, NR 14308).

In SGB, one tube (Row 67, Column 17) was plugged due to an undercut below the secondary face that reduced a tubesheet ligament below the minimum allowable per the ASME code. This hole was tubed normally, except that a shorter expansion was performed, prior to plugging (Reference 4.33, Appendix X, NR 10603).

10.2.2 Scored Tube Hole

During the review of plugged tubes in section 10.2.1 above, B&W non-conformance report NR 10603 was reviewed. This NR dealt with two tubesheet hole conditions; the first was the undercut that resulted in plugging the tube in SGB as discussed above.

The second non-conforming condition was a tubesheet hole in SGB that had several scratches on the hole ID (Row 75, Column 91). This hole was buffed to remove the raised, sharp edges of the scratches and the hole was tubed normally.

Leaving this tube in service was justified since it was felt that the scratch would not affect tubeability or the expansion. It was also stated that there should not be stress-corrosion cracking concerns since the hole was on the cold-leg side.

However, the statement that the hole was on the cold-leg side was incorrect; the hole is in fact in the hot leg and is therefore subjected to temperatures that are ~57°F higher.

10.2.3 Over-Expanded Tubes

During full-depth hydraulic expansion of SGA, twenty-eight (28) tubes were expanded beyond the secondary face of the tubesheet as a result of problems with the expansion mandrel (Reference 4.33, Appendix X, NR 13120). Twenty-five of these tubes actually had a "bulge" (albeit very small) above the secondary face.

After significant effort, including X-ray diffraction and finite-element analysis to determine residual stresses, and CERT (Constant Extension Rate Test) accelerated SCC testing, it was determined that the subject over-expanded tubes could be used-as-is (References 4.13 and 4.33, Appendix X, NR 13120).

The evaluation that justified these tubes being left in service determined that the measured residual stresses in the "bulge" region of representative over-expansions were below the threshold for SCC to occur in Alloy 690TT. Finite-element evaluations of the residual stresses at the "kink" at the tubesheet secondary face indicated that residual stresses may be greater than the SCC threshold over a very short distance, but accelerated CERT testing showed no increased SCC tendency over native tubing.

10.2.4 U-Bend Tube Proximity

The U-bend tube proximity issue discussed generically in section 9.2.1 has been confirmed to exist in a limited number of tubes at Ginna (Reference 4.34).

Low-frequency bobbin coil measurements were done during the 1997 and 1999 refueling outages to provide improved screening for this issue. The low-frequency bobbin coil is able to detect the presence of an adjacent tube if it is in close proximity due to increased penetration at lower frequencies.

Thirty-four (34) potential proximity indications were found in SGA by the low-frequency bobbin coil, with MRPC confirmation at 13 locations. No degradation was found at any of these locations.

Twenty-four (24) potential proximity indications were found in SGB by the low frequency bobbin coil, with

MRPC confirmation at 12 locations. No degradation was found at any of these locations.

Locations that were physically accessible on the secondary side were subsequently measured with gap gauges and proximity was confirmed. Measurements indicated that the threshold where MRPC could detect proximity was somewhere between 0.050" and 0.100". Random measurements of non-proximity locations were all > 0.200" (i.e. essentially nominal design spacing), providing further confidence in the ECT results.

10.2.5 Manufacturing Burnish Marks (MBMs)

Approximately 16,000 MBMs (manufacturing burnish marks) were documented in pre-operational baseline inspections. These were artifacts of the tube fabrication process and represent repairs of the tube OD surfaces by light polishing or grinding to remove slight surface imperfections.

These marks are not uncommon on steam generator tubing, but have no known impact on tube integrity. There is a concern that the presence of an MBM could mask degradation or that an MBM could be an incubation site for degradation.

Similar indications have been noted in destructive examinations of Alloy 600MA tubes from older steam generators (for example, Prairie Island-1, Zion-2, and Calvert Cliffs-1) and have not been associated with corrosion related degradation.

MBMs are considered a <u>precursor</u> to potential corrosion degradation, <u>not</u> a degradation mode themselves.

During the 1999 RFO, approximately *20%* of all *hot-leg accessible* MBMs with bobbin response > 5.0 Volts were characterized with MRPC. No degradation was found.

10.3 Active Damage Mechanisms at Ginna

No detectable degradation has been found in the Ginna RSGs. Therefore, there are no active damage mechanisms based on the definition in IP-SGP-2 (Reference 4.7).

10.4 Potential Degradation Mechanisms at Ginna

The degradation mechanisms in this section are considered to be potential mechanisms in the Ginna RSGs. This determination is made based on experience at other units with similar design and materials, or because a precursor condition is known to exist.

10.4.1 U-bend Wear

a. Description

U-bend wear is the most likely degradation mechanism to be seen during the 2002 RFO inspection. Several B&W RSG plants have experienced u-bend wear. This wear is generally believed to be the result of excessive tube-to-support clearances. The worst afflicted units are at Darlington. The design tube-to-support clearance was halved in the RSG units compared to Darlington, so general wear will be reduced. The wear seen at RSG units to date is very random and is believed to be the result of abnormally large clearances due to some form of tolerance stack-up.

Based on two inspection cycles of operation, Ginna is not believed to be susceptible to the "atypical" wear phenomenon discussed in section 9.2.4. It cannot be discounted however since it is possible that such damage was not noticed during the first inspection due to relatively small extent and was in the 50% of tubing not inspected during the second inspection.

The 50% bobbin sampling plan during the 1999 outage inspected two columns, then skipped two columns, then inspected two columns, etc. The columns skipped in 1999 will be inspected in 2002. As a precaution against a localized wear problem similar to what has been seen at other B&W RSGs, the entire uninspected column adjacent a wear indication will be inspected.

b. Degradation Model

The U-bend supports at Ginna use a staggered flat bar arrangement, with between two and four (depending on tube column) fan bars on each side of the u-bend apex connected to a collector bar. Wear is expected to occur over a small angle and over a short length (~1.25" to 1.5", the width of a fan or collector bar). It is possible for wear to occur over a slightly longer distance if it occurs near a fan/collector bar intersection.

The degradation model conservatively selected is "Uniform 360° Thinning over a Given Axial Length" from section 5.3.2 in the EPRI *Flaw Handbook* (Reference 4.2). A length of 3.15" is assumed since this corresponds to the length of a lattice grid "high bar". This length is conservative for U-bend wear.

c. Structural Limit

The structural limit calculated in Attachment 1, "Degradation Mode # 1: Lattice Grid Wear and Fan Bar Wear", for wear over a 3.15" length bounds the value for u-bend wear. The structural limit for normalized depth (to tube wall) is:

$$h_{STR} = 46.6\% \text{ TW}$$

This does not include burst correlation uncertainty, but does use conservative yield and ultimate strength values.

d. Technique (ETSS)

U-bend wear will be detected using ETSS 96004.2. This is a mid-range bobbin-coil technique applicable at tube supports, AVBs, and vertical and diagonal straps. See the ETSS and the applicable site-qualification documentation for more information.

e. Probability of Detection

From ETSS 96004.2, the probability of detection of the technique for flaws > 20% TW (which includes structurally significant wear) is > 90.9% at a lower-bound 90% confidence level. Therefore the technique is considered qualified for detection in accordance with the EPRI *Steam Generator Integrity Assessment Guidelines*.

From Reference 4.4, the percentage of wear indications detected by analysts was > 88.50% at a 90% lower-bound confidence level. The percentage was higher for structurally significant wear.

Therefore, the system POD is calculated to be:

$$POD_{sys} = POD_{tech} \cdot POD_{analyst} = (0.909)(0.885) = 80.4\%$$

Note that the real POD will be higher since the analyst uncertainty used was for a single analyst only; multiple analysts increase the probability of detection of the system.

f. Condition Monitoring Limit

The condition monitoring limit calculated in Attachment 1, "Degradation Mode # 1: Lattice Grid Wear and Fan Bar Wear", is:

$$h_{CM} = 40\% \text{ TW}$$

This limit includes technique and analyst sizing uncertainty.

g. Operational Assessment Limit

"Typical" growth rates seen from available data on the EPRI SGDD are:

McGuire 1: 20%TW (max) @ 3.6 EFPY = 5.6% TW/EFPY

McGuire 2: 14%TW (max) @ 2.5 EFPY = 5.6% TW/EFPY

Darlington 2: 35%TW (max) @ 5.3 EFPY = 6.6% TW/EFPY

Darlington 1: 20%TW (max) @ 3.7 EFPY = 5.4% TW/EFPY

St. Lucie 1 data from Reference 4.19 is not included since it is of the "localized typical" variety, and Ginna is not believed to be afflicted by that mechanism.

Based on the results above, a growth rate of 6% TW/EFPY seems realistic as a preliminary estimate. Ginna procedures require that this value be re-assessed based on the results of the upcoming inspection.

Recent data obtained from Ontario Power Generation (Reference 4.43) suggest that the maximum growth rate for U-bend wear at Darlington may be higher than suggested above. The maximum average growth rate observed in SG3 at Darlington-3 over 5.43 EFPY was 11.8% TW/EFPY. These growth rates are the result of excessive tube-to-support clearances at random locations within the Darlington u-bends.

These large growth rates are not believed to be representative for the Ginna steam generators. Based on at least two inspections of each and every tube (at the end of the first cycle and either the second or fourth cycle of operation), no wear has yet been detected. There is a very high probability that wear at even half the Darlington rate (6% TW/EFPY) would have been detected at the inspection following the second cycle of operation since the depth would have been on the order of 15% TW. Since all tubing has been inspected after ~2.5 EFPY or 5.3 EFPY of service and no wear was found, it is reasonable to assume that the Ginna u-bends are not afflicted by the abnormal tube-to-support clearance problems seen at Darlington.

Therefore, the Operational Assessment (OA) Limit for wear is equal to the Condition Monitoring limit minus the growth rate multiplied by the expected operating interval until the next inspection, which is 3.0 EFPY:

$$OA_{wear} = 40\%\ TW - 3\ EFPY \cdot 6\%\ TW/EFPY = 22\%\ TW$$

It is expected that the next two cycles (30 and 31) will have a total length of ~1000 EFPD, putting the next scheduled inspection at ~8.0 EFPY. If a wear indication was missed in the population of tubes inspected after the second cycle (~2.5 EFPY), then that tube will have accrued 5.5 EFPY between inspections. Postulating that the missed indication was 20% TW at that time and grew at 6% TW/EFPY, then it is possible that an indication may be found that is 53% TW at the next inspection in 2005. This exceeds the structural limit calculated in Attachment 1.

There are large conservatisms in the calculated structural limit in Attachment 1. Reducing just the wear length in Attachment 1 to 1.25" (representative of a fan bar) and increasing the material strength to 104% of the ASME minimum increases the calculated structural limit to greater than 53% TW. Although elevated temperature data is not available for the Ginna Alloy 690TT tubing, the values in the *Flaw Handbook* for 95/95 LTL properties for Westinghouse Alloy 690TT tubing is still significantly higher, so the 53% TW structural limit is still clearly very conservative.

Although a detailed statistical analysis will not be done, it is reasonable to assume that the probability of a wear scar that is 53% TW meeting the 3ΔP requirement is greater than 90% since the burst correlation is 90/50 and conservative material strengths are still being used.

The probability of both the primary and secondary analysts missing a 20% TW indication can be determined from probability theory to be 9.8% (based on the single analyst POD of 80.4% calculated above).

Assuming a 6% TW/EFPY growth rate (i.e. probability is 1.0), an *estimate* of the probability that a wear site will be found during the 2005 inspection that does not meet the structural integrity criterion is (0.098)(1.0)(1-0.9) = 0.0098 or less than 1%.

10.4.2 Lattice Grid Wear

Lattice grid wear is bounded by the discussion on U-bends in section 10.4.1 above. The Attachment 1 derivation of the CM limit was based on uniform 360° thinning over a length of 3.15". These limits were chosen based on the possibility of wear in one of the corners of a 6x6 lattice grid sub-cell. There is the possibility of wear on four sides, of which two sides will be high bars, which have a length of 3.15".

The growth rates for U-bend wear are bounding for lattice grids since the mass flow velocity will generally be greater in the U-bend. In addition, it is believed that manufacturing tolerance control (one of the factors implicated in wear seen to date) is better for lattice grid structures than for u-bend structures.

10.4.3 Tube Proximity Wear

a. <u>Description</u>

The U-bend proximity issue is described in some detail in sections 9.2.1 and 10.2.4 above. Additional information can be found in Reference 4.16.

The B&W discussion in Reference 4.16 concluded that upper bound "wall loss of about 33% over 40 years of operation and 40% over 60 years" could be expected. Furthermore, "The wear depth may progress noticeably in the first few years, i.e., after one fuel cycle the depth may be 5% for upper bound locations. This penetration rate will drop off rapidly as the contact area broadens."

Once again, u-bend tube proximity is a precursor to potential degradation, not an actual mechanism itself. There are presently no known instances of tube wear in a B&W RSG as a result of the tube proximity issue.

A number of potential tube proximity locations were confirmed during the 1997 refueling outage. Enhanced bobbin monitoring during the 1999 refueling outage found two additional locations per steam generator.

All previously identified locations will be monitored with +Point and Pancake rotating coils during the 2002 outage to verify that no wear is occurring. Proximity and proximity with wear ECT standards have been manufactured.

Tube proximity is believed to be a static phenomenon; tubes should not develop it over time since it is a product of initial manufacture. Two stiff leaf spring assemblies accommodate differential thermal growth between the two legs during operation, but prevent the u-bend structure from shifting over time (such as ratcheting out of position over several thermal cycles).

Note that if there is an indication of tube proximity wear, there should also be an indication in the tube below in that column; it is expected that the tubes will wear at approximately the same rate.

b. Degradation Model

The wear caused by U-bend tube proximity may be longer than the 3.15" limit assumed for fan bar and lattice grid wear above. However, the sensitivity to length at such large lengths is very small. Increasing the length of the uniform 360° thinning in the equation in Attachment 1 by 10x decreases the structural limit by 0.3% TW.

c. Structural Limit

The structural limit for wear at the U-bend will be nominally less than for U-bend fan bar or lattice grid wear. A limit of 46% TW is conservative. This does not include burst correlation uncertainty, but does use conservative yield and ultimate strength values.

d. Technique (ETSS)

** EXTENDED APPLICABILITY OF QUALIFIED TECHNIQUE **

Proximity wear in the U-bend will be detected by rotating +Point and Pancake coils. The applicable ETSS sheets are 96910.1 and 96911.1, which are qualified for detection of mechanically induced wear at broached tube support structures.

e. Probability of Detection

From the ETSS sheets, the probability of detecting mechanical wear is very high. It is reasonable to assume similar performance for tube proximity wear since the wear scar from one tube vibrating against another will be similar, although possibly longer. With this assumption, the technique POD for each will be on the order of 90%.

No specific data for analyst uncertainty is available for this application, but with two coils and two analysts (at least) it is certainly very high. An 11% wear scar on the tube proximity wear standard can be detected and allows the adjacent tube to be "mixed" out.

f. Condition Monitoring Limit

Any attempt to size the wear using the +Point or Pancake coils will be technically justified in accordance with Steam Generator Program requirements.

Unless sizing data can be justified, condition monitoring will be by in-situ pressure testing.

g. Operational Assessment Limit

When qualified techniques are extended to different applications, the EPRI *Steam Generator Integrity Assessment Guidelines* require that the tube be conservatively plugged on detection of degradation.

In the case of tube proximity wear, the peripheral tube and the tube below it would have to be plugged. If not, the colder peripheral tube may remain in contact with the tube below it, and the wear rate may actually increase.

10.4.4 Loose Part Wear

a. Description

Tubes in some steam generators have been damaged by the motion of loose parts against tubes, generally at the top of the tubesheet. Development of loose parts cannot be completely discounted, but the damage, if any, will generally be localized to a few tubes.

The need to search for loose part wear will be based on ECT inspection findings (from the bobbin or TTS RPC programs), or more likely in the event that secondary-side visual inspection reveals a loose part or visible tube damage.

b. Degradation Model

Wear due to loose parts will be bounded by the uniform 360° thinning solution used in calculating the structural limit for lattice grid and fan bar wear. For the same depth, loose parts wear is expected to be of much smaller extent than 360° around the wall. This constitutes the addition of material to the minimal material configuration of 360° uniform thinning over a 3.15″ length, and per the discussion on page 1-2 of the EPRI *Flaw Handbook*, adds structural reinforcement.

c. Structural Limit

The structural limit for loose parts wear will be bounded by the uniform thinning solution for U-bend fan bar and lattice grid wear which is 46.6% TW. This does not include burst correlation uncertainty, but does use conservative yield and ultimate strength values.

d. Technique (ETSS)

** EXTENDED APPLICABILITY OF QUALIFIED TECHNIQUE **

Loose parts wear will be detected with a +Point coil using ETSS 96910.1. Confirmation of suspected damage will be by pancake coil using ETSS 96911.1. These techniques are intended for detection of mechanically induced wear at broached tube supports, which is also a volumetric damage mechanism. See the ETSS and the applicable site-qualification documentation for more information.

e. Probability of Detection

It is reasonable to assume a very high POD, near 100%, based on the following:

- ETSS 96910.1 has a high probability of detecting structurally significant volumetric data based on the ETSS POD statistics.
- Loose part wear tends to be localized if it is in-bundle and thus the damaged region is easy to bracket. The extent of wear on the periphery can be determined by visual inspection.
- An NDD result during a loose part wear search in a suspect area is likely to receive additional review by resolution analysts and/or the RGE NDE Coordinator to prove a negative result.
- Pancake coil data will typically be available as well since the TTS inspection program will use a two-coil probe.

f. Condition Monitoring Limit

Any attempt to size the wear using the +Point or Pancake coils will be technically justified in accordance with Steam Generator Program requirements since the technique is not qualified for loose part wear. Another option is to use ETSS 21998.1, a new technique for sizing small wear indications in the freespan. A standard in accordance with this ETSS is not currently available, but a technical justification for use of a different standard may be possible to allow sizing using this technique.

Unless sizing data can be justified, condition monitoring will be by in-situ pressure testing.

g. Operational Assessment Limit

The EPRI *Steam Generator Integrity Assessment Guidelines* require that tubes be plugged on detection of degradation when a qualified technique is extended as in this case.

Loose part damage found will be plugged unless a technical justification is prepared to demonstrate that the tube may remain in service.

10.4.5 Damage due to Sludge Lancing Jet Impingement

a. Description

The sludge lancing system used to clean the tubesheet secondary face uses high-pressure water jets. These jets, if improperly aligned or operated at too high a pressure, can cause damage to steam generator tubing by jet impingement.

The RSG sludge lancing system underwent qualification testing to determine limits of operation for the system, and the system has not been operated near the qualification pressure, nor is it kept at a location for a significant period of time relative to the qualification time.

However, there are known instances where a sludge lancing system has caused damage to a steam generator (Reference 4.35, for example).

Jet impingement damage from sludge lancing would be expected in the first several tube rows. Damage would be expected within a few inches of the tubesheet since the jets are approximately one inch above the tubesheet face. The 20% TTS +Point/Pancake program, which looks at every fifth column up to 3″ above the tubesheet, should be sufficient to locate systematic sludge lance damage.

b. Degradation Model

Jet impingement wear due to sludge lancing will be bounded by the uniform 360° thinning solution used in calculating the structural limit for lattice grid and fan bar wear. For the same depth, jet impingement is expected to be of much smaller extent than 360° around the wall. This constitutes the addition of material to the minimal material configuration of 360° uniform thinning over a 3.15″ length, and per the discussion on page 1-2 of the EPRI *Flaw Handbook*, adds structural reinforcement.

c. Structural Limit

Per the discussion above, the structural limit for sludge lancing jet impingement wear will be bounded by the uniform thinning solution for U-bend fan bar and lattice grid wear, which is 46.6% TW. This does not include burst correlation uncertainty, but does use conservative yield and ultimate strength values.

d. Technique (ETSS)

** EXTENDED APPLICABILITY OF QUALIFIED TECHNIQUE **

Any damage caused by the sludge lance system will be detected with a +Point coil using ETSS 96910.1. Confirmation of suspected damage will be by pancake coil using ETSS 96911.1. These techniques are intended for detection of mechanically induced wear at broached tube supports, which is also a volumetric damage mechanism. See the ETSS and the applicable site-qualification documentation for more information.

e. Probability of Detection

This inspection is intended as a screening tool to verify that no systematic damage has occurred.

Nonetheless, it is expected based on the ETSS POD statistics that there is a high probability of detecting significant volumetric damage in the subject population, should it exist.

From basic probability, even a low POD technique has a relatively high probability of finding at least one indication in the subject population (~75 tubes) if a systematic damage mechanism exists.

f. Condition Monitoring Limit

Any attempt to size jet impingement wear using the +Point or Pancake coils will be technically justified in accordance with SG Program requirements since the technique is not qualified for this purpose. Another option is to use ETSS 21998.1, a new technique for sizing small wear indications in the tube freespan. A standard in accordance with this ETSS is not currently available, but a technical justification for use of a different standard may be possible to allow sizing using this technique.

Unless sizing data can be justified, condition monitoring will be by in-situ pressure testing.

g. <u>Operational Assessment Limit</u>

The EPRI *Steam Generator Integrity Assessment Guidelines* require that tubes be plugged on detection of degradation when a qualified technique is extended as in this case.

Jet impingement damage will be plugged unless a technical justification is prepared to demonstrate that the tube may remain in service. It is also possible that an OA justifying leaving tubes in service based on in-situ testing results from bounding indications (there may be many if damage is systematic) may be possible.

10.5 Damage Mechanisms Not Applicable to Ginna

10.5.1 Axial PWSCC at Dented Tube Supports

The lattice grid tube supports at Ginna are not susceptible to denting by design. The material (410S stainless) is much more resistant to corrosion than the carbon steel drilled hole supports in first generation plants.

A small number (37 total) of dent (DNT) and ding (DNG) indications > 2.0 Volts on bobbin were recorded during the 1999 outage. As a conservative measure, a 20% sample of DNT indications (ranked by voltage) that are accessible from the hot leg will be interrogated by rotating coils (+Point/ Pancake). No large deformation, with the corresponding high residual stresses, is believed to be occurring at these locations.

10.5.2 Pitting

Pitting generally occurs at low pH conditions with chlorides but also possibly with sulfates. Copper oxides from BOP components such as condensers and feed water heaters greatly accelerate pitting corrosion. Alloy 690TT may be somewhat more resistant to pitting than Alloy 600 but is not immune. Development of low pH conditions at Ginna are unlikely (in the original SGs, there were not any tubes plugged because of pitting) and recent data indicates that the crevices are caustic based on the sodium / chloride ratio. Further, most of the secondary side components containing copper have been replaced, resulting in very low copper transport to the steam generators (at least relative to early in plant life). Thus, tube repairs because of pitting are considered to be unlikely.

Although pitting is considered to be very unlikely, if present it will likely be found by the +Point / Pancake sampling done on 20% of the hot leg TTS expansions.

10.5.3 Wastage

Wastage is associated with phosphate water treatment; Ginna uses All-Volatile Treatment, therefore the mechanism is considered to be not applicable.

Although wastage is considered to be very unlikely, if present it will likely be found by the +Point / Pancake sampling done on 20% of the hot leg TTS expansions.

10.6 Damage Mechanisms Conservatively Treated as Potential Mechanisms

It is believed that corrosion-related degradation, particularly SCC, will eventually occur in Alloy 690TT material. In order to be conservative, the following mechanisms will be considered "potential", even though the likelihood of finding them at 5.0 EFPY is very small based on experience at other plants with longer service at higher temperatures).

10.6.1 Axial PWSCC at TTS Expansions

a. Description

Axial PWSCC has occurred at TTS expansions, expanded regions within tubesheets (hard rolls), apex of low-row u-bends, and at dented tube supports.

Design and operating features of the Ginna RSGs should mitigate these problems, including:

- Alloy 690TT tubing has been shown to be essentially immune to PWSCC (see section 7.1).

- Hydraulically expanded tube-to-tubesheet joints, which have lower residual stresses in both the tube and at the expansion transition.

- Lattice grid tube supports at Ginna are 410S stainless steel and have only line contact with the tubing. "Classical" denting is not credible in the Ginna RSGs, so PWSCC as a result of high residual stresses at these locations is also not considered credible.

- Larger diameter (and thus lower residual stress) u-bend tubes, commonly called "cross-over" tubes. Low-row u-bend cracking is addressed in section 10.6.6 below.

- Low hot leg temperature of ~590°F, which is one of the lowest in the industry. Corrosion mechanisms like PWSCC accelerate exponentially with temperature.

As discussed in section 10.2.3, twenty-eight tubes in SGA were expanded beyond the secondary-face of the tubesheet. Although they were dispositioned to use-as-is, these tubes are considered the most susceptible to PWSCC. As a leading indicator of PWSCC, these will be inspected every outage in which an inspection occurs.

Currently, 20% of the hot leg TTS transitions, in addition to all over-expanded tubes, are inspected during every outage in which inspections are planned, using rotating +Point probes. A combination +Point / Pancake probe will be used where possible.

b. <u>Degradation Model</u>

The degradation model conservatively selected for TTS axial cracking is "Freespan Throughwall Axial Cracking" from section 5.1.1 in the EPRI *Flaw Handbook* (Reference 4.2). This is the recommended approach in section 5.1.2, "Expansion Transition Axial Cracking", of the EPRI *Flaw Handbook*, with the length of the crack being taken as the length that extends out of the tubesheet beyond the last contact point with the tubesheet.

c. <u>Structural Limit</u>

The structural limit is calculated in Attachment 1, "Degradation Mode # 2: Freespan Axial Cracking".

The structurally limiting axial crack length, after subtracting for burst correlation uncertainties, and using conservatively minimum ASME code strength values, is:

$$L_{STR} = 0.286''$$

Again, this is the length of the crack that is not restrained by the tubesheet.

d. Technique (ETSS)

Axial PWSCC at the TTS expansion transition will be detected using the +Point coil in accordance with ETSS 20511.1. See the ETSS and the applicable site-qualification documentation for more information.

e. Probability of Detection

From ETSS 20511.1, the probability of detection of the technique for flaws > 40%TW is 88% at a lower-bound 90% confidence level. Therefore the technique is considered qualified for detection in accordance with the EPRI *Steam Generator Integrity Assessment Guidelines*.

From Reference 4.4, the percentage of PWSCC indications detected with rotating-coil by analysts was 88.69% at a 90% lower-bound confidence level. Therefore, the probability of the primary or the secondary analyst seeing the degradation, from basic probability theory, is:

$$POD_{analyst} = 0.8869 + 0.8869 - (0.8869)^2 = 98.7\%$$

Therefore, the system POD is calculated to be:

$$POD_{sys} = POD_{tech} \cdot POD_{analyst} = (0.88)(0.987) = 86.9\%$$

Note that when the combo probe with a Pancake coil is used, the POD will be higher, although this is not credited in this degradation assessment.

f. Condition Monitoring Limit

The condition monitoring limit calculated for freespan axial cracking in Attachment 1, which includes sizing uncertainty, is:

$$L_{CM} = 0.16''$$

Note that several references (4.6 and 4.14, for example) claim that rotating-coils (such as +Point) over-predict the structurally significant length of deep axial indications, and suggest using the structural limit value as the condition monitoring limit length. In the event that it is necessary to take this approach, an experienced vendor will be consulted and a technical justification prepared as part of the final condition monitoring. In-situ pressure testing of some or all crack indications will likely be carried out to support condition monitoring.

g. Operational Assessment Limit

All crack indications will be plugged prior to returning the unit to service, so there is no OA limit for indication sizing.

In the event that any crack indications are found, a vendor experienced in steam generator integrity assessment will be consulted during preparation of the CM and OA reports.

10.6.2 Circumferential PWSCC at TTS Expansions

a. Description

Circumferential PWSCC at the TTS expansion transitions is considered unlikely for the same reasons discussed for axial PWSCC in section 10.6.1. However, as with axial cracking, the over-expanded tubes are considered to be a leading indicator of this mechanism due to the locally high residual stresses.

b. Degradation Model

Circumferential PWSCC at the TTS expansions is modeled as discussed in section 5.2.1, "Circumferential Cracking with Restricted Lateral Tube Motion", in the EPRI *Flaw Handbook*.

It will be shown that the Ginna failure is expected to be "bending dominant" as opposed to "axial overload", so the correction factor for ID cracking in equation 5-18 of the EPRI *Flaw Handbook* does not need to be applied.

c. Structural Limit

The structural limit for circumferential PWSCC at TTS expansion transitions is calculated in Attachment 1, "Degradation Mode 5: Circumferential Cracking at TTS Expansions".

The structurally limiting PDA (Percent Degraded Area), after subtracting for burst correlation uncertainties, and using conservatively minimum ASME code strength values, is:

$$PDA_{STR} = 68.5\%$$

The nominal structurally limiting PDA is 71.5%, which is less than 75%, above which failure due to axial loading would be expected. Therefore the correct correlation was selected for failure.

d. Technique (ETSS)

Circumferential PWSCC at the TTS expansion transition will be detected using the +Point coil in accordance with ETSS 20510.1. See the ETSS and the applicable site-qualification documentation for more information.

e. Probability of Detection

From ETSS 20510.1, the probability of detection of the technique for structurally significant flaws > 40% TW is 91.5% at a lower-bound 90% confidence level. Therefore the technique is considered qualified for detection in accordance with the EPRI *Steam Generator Integrity Assessment Guidelines*.

From Reference 4.4, the percentage of PWSCC indications detected with rotating-coil by analysts was 88.69% at a 90% lower-bound confidence level. Therefore, the probability of the primary or the secondary analyst seeing the degradation, from basic probability theory, is:

$$POD_{analyst} = 0.8869 + 0.8869 - (0.8869)^2 = 98.7\%$$

Therefore, the system POD is calculated to be:

$$POD_{sys} = POD_{tech} \cdot POD_{analyst} = (0.915)(0.987) = 90.3\%$$

Note that when the combo probe with +Point and Pancake coils is used, the POD will be higher, although this is not credited in this analysis.

f. Condition Monitoring Limit

The condition monitoring limit calculated for circumferential PWSCC is calculated in Attachment 1, "Degradation Mode 3: Circumferential Cracking at TTS Expansions" under the "Circumferential PWSCC" sub-heading.

The CM limit for circumferential PWSCC, excluding the analyst error, which must be assumed to be zero at this time in the absence of better information, is:

$$PDA_{CM} = 58\%$$

In the event that crack indications are found, an experienced vendor will be consulted and a technical justification prepared for the analyst error as part of the final condition monitoring. In-situ pressure testing of some or all crack indications will likely be carried out to support condition monitoring.

g. Operational Assessment Limit

All crack indications will be plugged prior to returning the unit to service, so there is no OA limit for indication sizing.

In the event that any crack indications are found, a vendor experienced in steam generator integrity assessment will be consulted during preparation of the CM and OA reports.

10.6.3 Axial ODSCC at Tube Supports, Freespan, Sludge Pile, and Tubesheet Crevice

a. Description

Historically, support locations and the sludge pile have been sites for ODSCC in Alloy 600 tubing. Similar corrosion damage is not expected in Alloy 690TT tubing.

Axial ODSCC in the sludge pile and at lattice grids (eggcrates) can be located used Bobbin and +Point.

Currently, 20% of the hot leg TTS transitions plus all of the over-expanded tubes, from 3" above TTS to 2" below TTS, are inspected during every outage in which inspections are planned, using rotating +Point probes. A combination +Point / Pancake probe will be used where possible.

The bobbin and +Point programs will be used to test for ODSCC at supports and in the sludge pile.

b. Degradation Model

The degradation model selected for axial ODSCC is "Freespan Throughwall Axial Cracking" from section 5.1.1 in the EPRI *Flaw Handbook* (Reference 4.2). For structural integrity purposes, all axial cracks will conservatively be assumed to be 100% through wall.

c. Structural Limit

The structural limit is calculated in Attachment 1, "Degradation Mode # 2: Freespan Axial Cracking".

The structurally limiting axial crack length, after subtracting for burst correlation uncertainties, and using conservatively minimum ASME code strength values, is:

$$L_{STR} = 0.286''$$

d. Technique (ETSS)

Axial ODSCC at tube supports, in the freespan, sludge pile, and tubesheet crevice can be detected using the +Point coil in accordance with ETSS 21409.1, and with the Bobbin coil in accordance with ETSS 96008.1. See the ETSS sheets and the applicable site-qualification documentation for more information.

e. Probability of Detection

From ETSS 21409.1, the probability of detection of the technique for structurally significant flaws > 50% TW is 81.9% at a lower-bound 90% confidence level. Therefore the technique is considered qualified for detection in accordance with the EPRI *Steam Generator Integrity Assessment Guidelines*.

From Reference 4.4, the percentage of axial ODSCC indications that analysts detected with rotating coil data was 91.85% at a 90% lower-bound confidence level. Therefore, the probability of the primary <u>or</u> the secondary analyst seeing the degradation, from basic probability theory, is:

$$POD_{analyst} = 0.9185 + 0.9185 - (0.9185)^2 = 99.3\%$$

Therefore, the system POD is for +Point detection is calculated to be:

$$POD_{sys} = POD_{tech} \cdot POD_{analyst} = (0.819)(0.993) = 81.3\%$$

From ETSS 96008.1, the probability of detection of the bobbin technique for structurally significant flaws > 40% TW is 81.1% at a lower-bound 90% confidence level. Therefore the technique is considered qualified for detection in accordance with the EPRI *Steam Generator Integrity Assessment Guidelines*.

From Reference 4.4, the percentage of axial ODSCC indications that analysts detected with bobbin coil data was 79.54% at a 90% lower-bound confidence level. Therefore, the probability of the primary <u>or</u> the secondary analyst seeing the degradation, from basic probability theory, is:

$$POD_{analyst} = 0.7954 + 0.7954 - (0.7954)^2 = 95.8\%$$

Therefore, the system POD for Bobbin detection is calculated to be:

$$POD_{sys} = POD_{tech} \cdot POD_{analyst} = (0.811)(0.958) = 77.7\%$$

f. <u>Condition Monitoring Limit</u>

The condition monitoring limit for axial ODSCC is calculated in Attachment 1, "Degradation Mode 2: Freespan Axial Cracking" under the "Axial ODSCC Condition Monitoring Limit" sub-heading, is:

$$L_{CM} = 0.10''$$

Note that several references (4.6 and 4.14, for example) claim that rotating-coils (such as +Point) over-predict the structurally significant length of deep axial indications, and use the structural limit value as the condition monitoring limit length. In the event that it is necessary to take this approach, an experienced vendor will be consulted and a technical justification prepared as part of the final condition monitoring. In-situ pressure testing of some or all crack indications will likely be carried out to support condition monitoring.

g. Operational Assessment Limit

All crack indications will be plugged prior to returning the unit to service, so there is no OA limit for indication sizing.

In the event that any crack indications are found, a vendor experienced in steam generator integrity assessment will be consulted during preparation of the CM and OA reports.

10.6.4 Circumferential ODSCC at Expansion Transitions

a. Description

Circumferential cracking on the OD at the TTS expansion transitions in Alloy 600MA plants. The presence of tube over-expansions above the tubesheet secondary face in SGA makes this a potential degradation mechanism. The use of Alloy 690TT and low hot leg temperatures are factors that tend to reduce the likelihood of this mechanism.

b. Degradation Model

The degradation model for circumferential ODSCC is the same as for circumferential PWSCC. Since the failure mode is bending dominant, the ID/OD correction in section 5.2.1 (Eq'n 5-18) of the EPRI *Flaw Handbook* is not needed.

c. Structural Limit

From section 10.6.2 for circumferential PWSCC, the structurally-limiting PDA, after subtracting for burst correlation uncertainties, and using conservatively minimum ASME code strength values, is:

$$PDA_{STR} = 68.5\%$$

d. Technique (ETSS)

Circumferential ODSCC at the TTS expansion transition can be detected using the +Point coil in accordance with ETSS 21410.1. See the ETSS and the applicable site-qualification documentation for more information.

e. Probability of Detection

From ETSS 21410.1, the probability of detection of the technique for structurally significant flaws > 50% TW is 90.5% at a lower-bound 90% confidence level. Therefore the technique is considered qualified for detection in accordance with the EPRI *Steam Generator Integrity Assessment Guidelines*.

From Reference 4.4, the percentage of circumferential ODSCC indications that analysts detected with rotating coil data was 87.34% at a 90% lower-bound confidence level. Therefore, the probability of the primary or the secondary analyst seeing the degradation, from basic probability theory, is:

$$POD_{analyst} = 0.8734 + 0.8734 - (0.8734)^2 = 98.4\%$$

Therefore, the system POD is calculated to be:

$$POD_{sys} = POD_{tech} \cdot POD_{analyst} = (0.905)(0.984) = 89\%$$

f. Condition Monitoring Limit

An attempt to calculate the condition monitoring limit for circumferential ODSCC is made in Attachment 1, "Degradation Mode 5: Circumferential Cracking at TTS Expansions" under the "Circumferential ODSCC" sub-heading. However, the technique is not able to adequately size ODSCC indications, either in terms of PDA or length (from which a conservative PDA could be determined).

Condition monitoring for circumferential ODSCC indications, if found, will be by in-situ pressure testing.

g. Operational Assessment Limit

All crack indications will be plugged prior to returning the unit to service. In the event that any crack indications are found, a vendor experienced in steam generator integrity assessment will be consulted during preparation of the CM and OA reports.

10.6.5 Manufacturers Burnish Marks (MBMs)

a. Description

A large number of MBMs, which are not considered to be a degradation mechanism, are present on the Ginna RSG tubing (see section 10.2.5). Although degradation at MBMs is not expected, it has been decided that a conservative approach should be taken to monitor these sites.

At each ISI, any tube that has ever exhibited an MBM response ≥5.0V or an MBM of measurable depth on a mix channel during a previous ISI will be added to the current bobbin tube list. All MBM calls ≥2.5V or that have measurable depth on a mix channel during the current ISI bobbin program will be sent to resolution for comparison to baseline results.

At least 20% of the *hot-leg accessible* indications ≥5.0V, plus any others that have exhibited a significant change in voltage, phase, or signal characteristics on the bobbin coil will be spun using the +Point coil as a minimum.

b. Degradation Model

For structural integrity purposes, MBMs can be considered to be areas of small extent with minor wall thinning. The uniform 360° wear degradation model used for lattice grids and fan bars may be conservatively used.

c. Structural Limit

The structural limit for lattice grid and fan bar wear would be bounding in this application. However, since they are very shallow, no MBM approaches structural, condition monitoring, or repair limits.

d. Technique (ETSS)

MBMs can be detected using a bobbin coil and ETSS 96010.1, which was specifically developed for this purpose. See the ETSS and the applicable site-qualification documentation for more information.

e. Probability of Detection

POD is not a relevant parameter in this case. All MBMs have been present since tubing manufacture. By the end of the 2002 outage bobbin inspection all tubing will have received at least three complete inspections (baseline-100%, 1997-100%, 1999-50%, 2002-50%). Since the reporting criteria for MBMs is 2.5V, which is easily seen, and the 5V threshold that puts them on the retest list every outage is even higher, it is reasonable to conclude that all significant MBMs have been found at this time.

f. Condition Monitoring Limit

As discussed above, the depths of all MBMs are well below any limit where structural failure could occur.

Condition monitoring limits for any degradation that may be detected at MBM sites will be determined when the morphology of the degradation is determined.

g. Operational Assessment Limit

Operational assessment limits for any degradation that may be detected at MBM sites will be determined when the morphology of the degradation is determined and documented in the Operational Assessment.

10.6.6 Inner-Row U-Bend Cracking

a. Description

Inner-row U-bend cracking has been a problem in Westinghouse steam generators with Alloy 600MA tubing, and is a consequence of residual stresses in the tight radius bends. Based on a review of the EPRI *Steam Generator Reference Book*, this cracking phenomenon is axial in nature (Reference 4.41).

Problems with the inner-row U-bends were addressed in the Ginna RSGs by material selection (Alloy 690TT), design changes to maximize the bend radius of inner-row tubes (cross-over tubes) and by a stress relieving heat treatment after bending of all tubes up to a 12″ bend radius (Reference 4.40). After heat treatment, the residual stress in the u-bend would not be expected to differ significantly from straight tube. Based on this, the probability of inner-row u-bend cracking is considered to be very low.

b. Degradation Model

Inner-row U-bend cracking is bounded by the solution for through wall axial cracking per section 5.1.2 of the EPRI *Flaw Handbook* (Reference 4.2). This solution is conservative since there are strengthening effects due to the bend, although the additional strength due to cold work is not present due to the stress relief step.

c. Structural Limit

Since there is a strengthening effect due to the tube bend, the solution previously derived in Attachment 1, "Degradation Mode 2: Freespan Throughwall Axial Cracks (Structural Integrity of Axial Cracks)" applies. The structurally limiting length, including uncertainty in the burst correlation, is 0.286".

d. Technique (ETSS)

ETSS 96511.2 can detect circumferential and axial PWSCC in low-row U-bend tubes. See the ETSS and the applicable site-qualification documentation for more information.

e. Probability of Detection

From ETSS 96511.2, the probability of detection of the technique for all flaws is 91.5% at a lower-bound 90% confidence level. Therefore the technique is considered qualified for detection in accordance with the EPRI *Steam Generator Integrity Assessment Guidelines*.

From Reference 4.4, the percentage of circumferential ODSCC indications (which was less than PWSCC data so will be used here) that analysts detected with rotating coil data was 87.34% at a 90% lower-bound confidence level. Therefore, the probability of the primary or the secondary analyst seeing the degradation, from basic probability theory, is:

$$POD_{analyst} = 0.8734 + 0.8734 - (0.8734)^2 = 98.4\%$$

Therefore, the system POD is calculated to be:

$$POD_{sys} = POD_{tech} \cdot POD_{analyst} = (0.915)(0.984) = 90.0\%$$

f. Condition Monitoring Limit

Correlations to depth size U-bend cracking are not particularly good. Condition monitoring will be by in-situ pressure testing.

g. Operational Assessment Limit

All crack indications will be plugged prior to returning the unit to service. In the event that any crack indications are found, a vendor experienced in steam generator integrity assessment will be consulted during preparation of the CM and OA reports.

11 Leakage Considerations

The issue of accident-induced leakage is addressed in a bounding way by demonstrating that a given degradation mechanism will not burst at limiting accident pressure differentials.

This approach is not applicable for degradation that is already progressed through wall and exhibits leakage during normal operation. Since there is no detectable activity on the secondary-side of the Ginna RSGs at this time, all degradation will be treated with the bounding model.

Table 1 contains the condition monitoring limit that ensures that the degradation will not proceed through the wall of the tube and leak. All values are derived in Attachment 1.

Note that for some degradation mechanisms (circumferential ODSCC, for example) it is not possible to realistically size the degradation. In-situ pressure testing is required to verify that leakage integrity was maintained for the condition monitoring assessment.

12 Secondary-Side Degradation Assessment

To date, no degradation has been found in the secondary-side internals of a B&W replacement steam generator (Reference 4.38).

The author of this degradation assessment is aware of two instances of secondary-side degradation in the steam generators at Point Lepreau NGS. The first mechanism involved erosion/cavitation damage at a joint where the emergency feedwater headers were slip jointed into the shroud. No similar configuration exists at Ginna so this is not considered to be relevant.

The second degradation mechanism seen at Point Lepreau was a single secondary separator (out of ~80) that had degraded welds at the joint between the bottom plate and the eight inlet vanes. All eight welds on the one separator were highly porous and were hematite red, instead of the expected black that would be present if there was a stable magnetite layer. The secondary separators at Point Lepreau are a similar design to those at Ginna (except that they are removable).

These welds were inspected as best they could be during the 1997 outage. A simple camera tool has been designed to allow rapid visual inspection during the upcoming outage.

With no other known degradation, a general condition assessment of the secondary-side of SGB will be carried out during the upcoming outage. A copy of the inspection plan can be found in Attachment 2.

13 In-Situ Pressure Test Screening Criteria

In-situ pressure test screening criteria will be developed on an as-need basis. Based on a review of in-situ pressure test database on SGDD, there is a single instance of a replacement steam generator being in-situ tested (Almaraz 1, in 1987). However, reviewing SG replacements, it turns out that the Almaraz 1 steam generators were replaced in 1996, so the single data point is clearly in error.

RG&E has elected to not deploy the in-situ pressure testing equipment to site as a cost saving measure. There will be adequate time to determine in-situ candidates if it becomes necessary to deploy the equipment.

TABLE 1
Summary of Degradation Assessment

Mechanism / Location	ETSS / Probe	Structural Limit	CM Limit (Structural)	CM Limit (Leakage)	OA Limit	Sample Plan	Notes
Wear / U-bend	96004.2 / Bobbin MR	<46%TW	<40%TW	<63%TW	22%TW	50% Bobbin Program	1,5,6,13
Wear / Lattice Grids	96004.2 / Bobbin MR	<46%TW	<40%TW	<63%TW	22%TW	50% Bobbin Program	1,5,13
Wear / Tube Proximity in U-bend	96910.1 / +Point 96911.1 / Pancake MR	<46%TW	PT or TJ	PT or TJ	PD or TJ	50% Bobbin Program (screen for changes from 97RFO) Spin known + changed locations	1,2,3,7
Wear / Loose Parts	96910.1 / +Point 96911.1 / Pancake MR	<46%TW	PT or TJ	PT or TJ	PD or TJ	Only if detected on Bobbin, +Point, or visually	1,2,3,4
Volumetric / Sludge Lance Jet Impingement	96910.1 / +Point 96911.1 / Pancake MR	<46%TW	PT or TJ	PT or TJ	PD or TJ	Screening based on 20% HL TTS (+3"/-2") Program	1,2,3,4,8
The following mechanisms are considered extremely unlikely at this time, but are conservatively assumed to be potential mechanisms:							
Axial PWSCC / TTS Expansions	20511.1 / +Point	L<0.29"	L<0.16"	<60%TW (max)	PD	20% HL TTS (+3"/-2") Program + 28 OXP (SGA)	9,10,13
Circ PWSCC / TTS Expansions	20510.1 / +Point	PDA<68%	PDA<58%	PT	PD	20% HL TTS (+3"/-2") Program + 28 OXP (SGA)	10,11
Axial ODSCC / Tube Supports, Freespan, Sludge Pile, TTS Crevice	96008.1 / Bobbin MR 21409.1 / +Point	L<0.29"	L<0.10"	<46%TW (max)	PD	50% Bobbin Program 20% HL TTS (+3"/-2") Program + 28 OXP (SGA)	9,10,13
Circ ODSCC / Expansions	21410.1 / +Point	PDA<68%	PT	PT	PD	20% HL TTS (+3"/-2") Program + 28 OXP (SGA)	10,
Axial Cracks / Inner-Row U-bends	96511.2 / +Point	<46%TW	PT	PT	PD	20% R1/R2 U-bends	10,14
Other / MBM	96010.1 / Bobbin MR NA / +Point	TBD	TBD	TBD	PD	See section 10.6.5	12

PT – In-Situ Pressure Test
TJ – Technical Justification required due to inadequate information at time of degradation assessment
PD – Plug-on-Detection
TBD – To Be Determined

Mechanisms Considered N/A for Ginna: Inter-Granular Attack, Wastage, Pitting, Axial PWSCC at Dented Supports

NOTES: **See next page**

TABLE 1
Summary of Degradation Assessment

NOTES:

1. The 46% through wall structural limit for volumetric degradation does not include burst correlation uncertainty, but is based on conservative yield and ultimate strength values for Alloy 690TT at 650°F.
2. The mid-range pancake coil will be used to confirm degradation.
3. These qualified techniques are being extended to another application. A technical justification will be required before using sizing information in CM/OA.
4. New ETSS 21998.1 may also be able to size these mechanisms. Use of a different standard than specified in this ETSS will require technical justification.
5. OA limits are based on a wear rate of 6% TW/EFPY from other B&W steam generators. This must be validated based on wear rate observed at Ginna.
6. When U-bend fan bar wear is found, the adjacent uninspected column shall be inspected to protect against the mechanism discussed in section 9.2.3.
7. When a proximity wear indication is found, the tube below will also exhibit wear.
8. The Ginna sludge lance system is operated below qualification limits; this mechanism is postulated based on experience at other plants.
9. Structural CM length includes length uncertainty from ETSS; several references suggest ECT over-estimates structurally significant length of deep cracks and that structural limit may be used for CM. This would require a technical justification.
10. The structural limits for these mechanisms include burst correlation uncertainty and conservative yield and ultimate strength values.
11. These CM limits do not include analyst uncertainty since sufficient information is unavailable. Technical justification required for analyst uncertainty.
12. MBMs are not a degradation mechanism. MBM screening is a precaution to detect degradation that may initiate at these sites. Structural, CM, and OA limits cannot be specified until a degradation mechanism is known to exist.
13. CM limit for leakage is maximum depth for indication that will not go through wall under accident differential pressure.
14. Ginna U-bends are heat treated to minimize residual stresses to 12" bend radius. Cracking is considered to be extremely unlikely.

ATTACHMENT 1

Calculation of Structural, CM, and OA Limits

Alloy 690 Material Properties

$S_u := 80 \cdot ksi$ (Design Input 3.4.1)

$S_y := 35.2 \cdot ksi$ (Design Input 3.4.2)

$\sigma_M := 0 \cdot ksi$ No uncertainty in Material Strength since ASME Code minimum values used

Tube Dimensions

$OD_{tube} := 0.750 \cdot in$ $\quad R_o := \frac{OD_{tube}}{2}$ $\quad R_o = 0.375\,in$ (Design Input 3.2)

$t_{wall} := 0.043 \cdot in$ (Design Input 3.3)

$R_i := \frac{\left(OD_{tube} - 2 \cdot t_{wall}\right)}{2}$ $\quad R_i = 0.332\,in$

$R_m := \frac{R_i + R_o}{2}$ $\quad R_m = 0.3535\,in$

Process Pressures and Differential Pressures

$P_{RCSnom} := 2235 \cdot psig$ RCS Normal Operating Pressure (Design Input 3.5)

$P_{RCSmax} := 2485 \cdot psig$ RCS Design Pressure and PZR Safety Valve Set Pressure (Design Input 3.6)

$P_{SGnom} := 735 \cdot psig$ Normal SG Secondary-Side Pressure (Design Input 3.8)

$P_{SGmax} := 1085 \cdot psig$ Maximum SG Secondary-Side Pressure (Design Input 3.8)

$P_{SGmin} := 0 \cdot psig$ Minimum (post-MSLB) SG Secondary-Side Pressure (Design Input 3.9)

The Normal Operating Differential Pressure is:

$\Delta P_{NO} := P_{RCSnom} - P_{SGnom}$ $\quad \Delta P_{NO} = 1500\,psig$

The Accident-Induced Differential Pressure is:

$\Delta P_{ACC} := P_{RCSmax} - P_{SGmin}$ $\quad \Delta P_{ACC} = 2485\,psig$

The pressure to be used in integrity assessment is the greater of three times the normal operating differential pressure or 1.4 times the accident-induced differential pressure. There the "integrity assessment" differential pressure is:

$\Delta P_{IA} := \max\left(3 \cdot \Delta P_{NO}, 1.4 \cdot \Delta P_{ACC}\right)$ $\quad \Delta P_{IA} = 4500\,psi$

Degradation Mode # 1: Lattice Grid Wear and Fan Bar Wear

Wear at lattice grids and fan bars will be modeled as uniform 360° wear over a length of a lattice grid high bar. This is conservative since in reality the wear will be over a limited circumferential extent. Nonetheless, it is possible for a tube in the corner sub-cell of a 6x6 lattice grid to have wear on three sides at a given elevation, with the length equal to the high bar height of 3.15".

$L_{hb} := 3.15 \cdot in$ $\quad\sigma_{Lhb} := 0 \cdot in$ No length uncertainty since it is width of a high bar; length has very small impact for "long" scars

$\alpha := -0.139$ $\quad\sigma_{\alpha} := 0.0543$

$\sigma_{hT} := 3.74\%$ Using ETSS 96004.2 data

$\sigma_{hA} := 3.81\%$ D. H. Harris Paper (Reference 4.4)

$\sigma_h := \sqrt{\sigma_{hA}^2 + \sigma_{hT}^2}$ $\qquad \sigma_h = 5.3389\,\%$

$Z := 1.282$

$h := 0.5$ Initial Guess at normalized wear depth

Using simplified statistical method:

Obtain Structural Limit from Burst Pressure Correlation:

Given

$$\Delta P_{IA} = 0.598 \cdot \frac{(S_y + S_u) \cdot t_{wall}}{R_m} \cdot (1-h)^{1-e^{\frac{\alpha \cdot L_{hb}}{\sqrt{R_m \cdot t_{wall} \cdot (1-h)}}}}$$

$h_{SL} := \mathrm{Find}(h)$ $\qquad h_{SL} = 46.6\,\%$ Structural Limit, %TW

Determine Uncertainty in Normalized Depth due to Material Strength Uncertainty:

Given

$$\Delta P_{IA} = 0.598 \cdot \frac{(S_y + S_u - Z \cdot \sigma_M) \cdot t_{wall}}{R_m} \cdot (1-h)^{1-e^{\frac{\alpha \cdot L_{hb}}{\sqrt{R_m \cdot t_{wall} \cdot (1-h)}}}}$$

$h_M := \mathrm{Find}(h)$ $\qquad h_M = 46.56\,\%$

$Z\sigma_M := h_{SL} - h_M$ $\qquad Z\sigma_M = 0.00\,\%$

Determine Uncertainty in Normalized Depth due to correlation parameter α Uncertainty:

Given

$$\Delta P_{IA} = 0.598 \cdot \frac{(S_y + S_u) \cdot t_{wall}}{R_m} \cdot (1-h)^{1-e^{\frac{(\alpha - Z \cdot \sigma_\alpha) \cdot L_{hb}}{\sqrt{R_m \cdot t_{wall} \cdot (1-h)}}}}$$

$h_\alpha := \mathrm{Find}(h)$ $\qquad h_\alpha = 46.32\,\%$

$Z\sigma_\alpha := h_{SL} - h_\alpha$ $\qquad Z\sigma_\alpha = 0.24\%$

Determine Uncertainty in Normalized Depth due to Length Uncertainty:

Given

$$\Delta P_{IA} = 0.598 \cdot \frac{(S_y + S_u) \cdot t_{wall}}{R_m} \cdot (1-h)^{1-e^{\frac{\alpha \cdot (L_{hb} + Z \cdot \sigma_{Lhb})}{\sqrt{R_m \cdot t_{wall} \cdot (1-h)}}}}$$

$h_L := \mathrm{Find}(h)$ $\qquad h_L = 46.56\%$

$Z\sigma_L := h_{SL} - h_L$ $\qquad Z\sigma_L = 0.00\%$

Get the SRSS of the Uncertainty in Normalized Depth:

$$Z\sigma_h := \sqrt{(Z\sigma_M)^2 + (Z\sigma_\alpha)^2 + (Z\sigma_L)^2 + Z^2 \cdot \left(\sigma_{hA}{}^2 + \sigma_{hT}{}^2\right)} \qquad Z\sigma_h = 6.8486\%$$

The final Condition Monitoring Limit for Wear, at 90%/50% probability/confidence is:

$h_{CM} := h_{SL} - Z\sigma_h$ $\qquad h_{CM} = 40\%$ $\qquad$ Condition Monitoring Limit, %TW

Now determine the CM limit for leakage using a bounding approach. This is the limiting normalized wear depth that will not leak under the limiting accident induced differential pressure.

Given

$$\Delta P_{ACC} = 0.598 \cdot \frac{(S_y + S_u - Z \cdot \sigma_M) \cdot t_{wall}}{R_m} \cdot (1 - h - Z \cdot \sigma_h)^{1-e^{\frac{(\alpha - Z \cdot \sigma_\alpha) \cdot (L_{hb} + Z \cdot \sigma_{Lhb})}{\sqrt{R_m \cdot t_{wall} \cdot (1 - h - Z \cdot \sigma_h)}}}}$$

$h_{CML} := \mathrm{Find}(h)$ $\qquad h_{CML} = 63.5\%$ $\qquad$ Leakage Limit, %TW

As expected, the CM limit to satisfy the structural integrity performance criterion is more limiting than the CM limit to satisfy the Accident-Induced Leakage Performance Criterion. For other volumetric indications that are bounded by uniform thining, but for which the depth sizing uncertainty isn't known, the limiting wall loss, without depth sizing uncertainty, is:

Given

$$\Delta P_{ACC} = 0.598 \cdot \frac{(S_y + S_u - Z \cdot \sigma_M) \cdot t_{wall}}{R_m} \cdot (1-h)^{1-e^{\frac{(\alpha - Z \cdot \sigma_\alpha) \cdot (L_{hb} + Z \cdot \sigma_{Lhb})}{\sqrt{R_m \cdot t_{wall} \cdot (1-h)}}}}$$

$h_{SLL} := \mathrm{Find}(h)$ $\qquad h_{SLL} = 70.3\%$ $\qquad$ Leakage Limit, %TW

This limit, along with depth sizing uncertainty (if available) can be used for other volumetric degradation modes.

Degradation Mode # 2: Freespan Throughwall Axial Cracking (Structural Integrity of Axial Cracks)

The freespan throughwall axial cracking model in section 5.1.1 of Reference 4.2 will be used to assess the structural integrity of axial cracks. All cracks will be conservatively assumed to be throughwall.

Parameters used to determine the burst pressure and burst pressure correlation uncertainty are:

$b_1 := 0.061319$ $\quad R_{11} := 0.13643$

$b_2 := 0.53648$ $\quad R_{21} := -0.13024$ $\quad R_{22} := 0.14081$

$b_3 := -.2778$ $\quad R_{31} := -0.14613$ $\quad R_{32} := 0.13181$ $\quad R_{33} := 0.17452$

First determine the structural limit without any uncertainties:

$$L_{STR} := \frac{\sqrt{R_m \cdot t_{wall}}}{b_3} \cdot \ln\left[\frac{\frac{\Delta P_{IA} \cdot R_m}{(S_y + S_u) \cdot t_{wall}} - b_1}{b_2}\right] \qquad L_{STR} = 0.3218 \text{ in}$$

Now determine the normalized length:

$$\lambda := \frac{L_{STR}}{\sqrt{R_m \cdot t_{wall}}} \qquad \lambda = 2.6101$$

Determine the components of the standard deviation of the relational error:

$s := 0.01715$ Standard deviation of P_N regression from paragraph below Eq'n 5-3 in EPRI *Flaw Handbook* (Reference 4.2)

$f_2 := e^{b_3 \cdot \lambda}$ $\qquad f_2 = 0.4843$

$f_3 := b_2 \cdot \lambda \cdot f_2$ $\qquad f_3 = 0.6781$

Now determine the standard deviation of the normalized burst pressure relational error from Eq'n 5-6 in the EPRI *Flaw Handbook*:

$$\sigma_R := s \cdot \sqrt{1 + R_{11} + f_2^{\,2} \cdot R_{22} + f_3^{\,2} \cdot R_{33} + 2 \cdot (f_2 \cdot R_{21} + f_3 \cdot R_{31} + f_2 \cdot f_3 \cdot R_{32})} \qquad \sigma_R = 0.01725$$

Using the relational error, determine the 90/50 uncertainty in the structural length due to the error in the normalized burst pressure correlation:

$$Z\sigma_{LR} := L_{STR} - \frac{\sqrt{R_m \cdot t_{wall}}}{b_3} \cdot \ln\left[\frac{\frac{\Delta P_{IA} \cdot R_m}{(S_y + S_u) \cdot t_{wall}} + Z \cdot \sigma_R - b_1}{b_2}\right] \qquad Z\sigma_{LR} = 0.0363 \text{ in}$$

Now determine the 90/50 uncertainty in the structural length due to the uncertainty in the Material Strength:

$$Z\sigma_{LM} := L_{STR} - \frac{\sqrt{R_m \cdot t_{wall}}}{b_3} \cdot \ln\left[\frac{\frac{\Delta P_{IA} \cdot R_m}{(S_y + S_u - Z \cdot \sigma_M) \cdot t_{wall}} - b_1}{b_2}\right] \qquad Z\sigma_{LM} = 0.0000 \text{ in}$$

The structural limit length will be reduced by the SRSS of the material and correlational uncertainty:

$$L_{RED} := L_{STR} - \sqrt{(Z\sigma_{LM})^2 + (Z\sigma_{LR})^2} \qquad L_{RED} = 0.2855 \text{ in}$$

Axial PWSCC Structural Integrity Condition Monitoring Limit:

For sizing the length of an axial PWSCC indication, the technique performance data from ETSS 20511.1 is used:

$R := \sqrt{0.79}$ $\qquad R = 0.8888$

The discussion in section 4.6 of the EPRI *Steam Generator Integrity Assessment Guidelines* (Reference 4.1) requires that the correlation coefficient be greater than the value required to have 95% confidence that the correlation actually exists. For this ETSS, there are 18 data points; this clearly exceeds the requirement in Table 4-2 of the Integrity Assessment Guidelines.

Using the technique regression in ETSS 20511.1, the ECT length of an indication at a "truth" length equal to the reduced length calculated above is:

$L_{NDE} := 0.77 \cdot L_{RED} + 0.08 \cdot in$ $\qquad L_{NDE} = 0.30\,in$

The RMSE length measurement error of the technique is:

$RMSE_L := 0.11 \cdot in$

The analyst error will assumed to be zero. This is reasonable since it is known that rotating probes over-estimate the structurally significant length of an indication (see Appendix B, Axial Defects, in the EPRI *Steam Generator In-Situ Pressure Test Guidelines*, Reference 4.6). Therefore, the condition monitoring length for throughwall axial cracks will be:

$L_{CM} := L_{NDE} - Z \cdot RMSE_L$ $\qquad L_{CM} = 0.16\,in$

Axial ODSCC Structural Integrity Condition Monitoring Limit:

For sizing the length of an axial ODSCC indication, the technique performance data from ETSS 21409.1 is used.

$R := \sqrt{0.84}$ $\qquad R = 0.9165$

The discussion in section 4.6 of the EPRI *Steam Generator Integrity Assessment Guidelines* (Reference 4.1) requires that the correlation coefficient be greater than the value required to have 95% confidence that the correlation actually exists. For this ETSS, there are 22 data points; this clearly exceeds the requirement in Table 4-2 of the Integrity Assessment Guidelines.

Using the technique regression in ETSS 21409.1, the ECT length of an indication at a "truth" length equal to the reduced length calculated above is:

$L_{NDE} := 0.76 \cdot L_{RED} + 0.12 \cdot in$ $\qquad L_{NDE} = 0.337\,in$

The RMSE length measurement error of the technique is:

$RMSE_L := 0.18 \cdot in$

The analyst error will assumed to be zero. This is reasonable since it is known that rotating probes over-estimate the structurally significant length of an indication (see Appendix B, Axial Defects, in the EPRI *Steam Generator In-Situ Pressure Test Guidelines*, Reference 4.6). Therefore, the condition monitoring length for throughwall axial cracks will be:

$L_{CM} := L_{NDE} - Z \cdot RMSE_L$ $\qquad L_{CM} = 0.1062\,in$

Degradation Mode # 3: Part-Throughwall Axial Cracking (Accident Leakage Integrity for PWSCC Cracks at TTS)

In order to determine a CM leakage limit for axial PWSCC cracks, the maximum depth of a "long" ID crack that will not burst at the accident-induced differential pressure will be determined.

Use part-throughwall crack correlation, Reference 4.2 section 5.1.4:

$\sigma_c := 0.0705$ Coefficient Uncertainty

$h_{eff} := 50\%$ Initial Guess at effective depth

$L_{eff} := 3 \cdot in$ Effective Length ("Long" crack assumed, with no uncertainty)

Given

$$\Delta P_{ACC} = 0.58 \cdot (S_y + S_u) \cdot \frac{t_{wall}}{R_i} \cdot \left(1.104 - \frac{L_{eff}}{L_{eff} + 2 \cdot t_{wall}} \cdot h_{eff}\right) \cdot \frac{1}{1 + \frac{t_{wall}}{R_i} \cdot h_{eff} \cdot \frac{L_{eff}}{L_{eff} + 2 \cdot t_{wall}}}$$

$h_{LL} := \mathrm{Find}(h_{eff})$ $h_{LL} = 81.01\%$ Structural Limit at Accident-Induced Pressure Difference

Determine the SRSS uncertainty component due to material strength uncertainty:

Given

$$\Delta P_{ACC} = 0.58 \cdot (S_y + S_u - Z \cdot \sigma_M) \cdot \frac{t_{wall}}{R_i} \cdot \left(1.104 - \frac{L_{eff}}{L_{eff} + 2 \cdot t_{wall}} \cdot h_{eff}\right) \cdot \frac{1}{1 + \frac{t_{wall}}{R_i} \cdot h_{eff} \cdot \frac{L_{eff}}{L_{eff} + 2 \cdot t_{wall}}}$$

$Z\sigma_{hM} := h_{LL} - \mathrm{Find}(h_{eff})$ $Z\sigma_{hM} = 0.0000\%$

Determine the SRSS uncertainty component due to burst correlation coefficient uncertainty

Given

$$\Delta P_{ACC} = 0.58 \cdot (S_y + S_u) \cdot \frac{t_{wall}}{R_i} \cdot \left(1.104 - Z \cdot \sigma_c - \frac{L_{eff}}{L_{eff} + 2 \cdot t_{wall}} \cdot h_{eff}\right) \cdot \frac{1}{1 + \frac{t_{wall}}{R_i} \cdot h_{eff} \cdot \frac{L_{eff}}{L_{eff} + 2 \cdot t_{wall}}}$$

$Z\sigma_{hR} := h_{LL} - \mathrm{Find}(h_{eff})$ $Z\sigma_{hR} = 8.9638\%$

The SRSS uncertainty, exluding NDE technique and analyst errors, is:

$h_{RED} := h_{LL} - \sqrt{(Z\sigma_{hM})^2 + (Z\sigma_{hR})^2}$ $h_{RED} = 72.0493\%$

The corresponding NDE depth (since ETSS 20511.1 tends to overcall maximum depth) is:

$h_{NDE} := 0.84 \cdot h_{RED} + 27.83\%$ $h_{NDE} = 88.35\%$

The corresponding CM limit, to have confidence that an axial crack at the expansion transition will not leak, is:

$RMSE := 21.75\%$

$h_{CMAL} := h_{NDE} - Z \cdot RMSE$ $\qquad$ $h_{CMAL} = 60.468\,\%$

There is additional conservatism in this calculation since the maximum NDE depth is used against the CM criteria, whereas the burst correlation is based on the effective depth.

Degradation Mode # 4: Part-Throughwall Axial Cracking (Accident Leakage Integrity for ODSCC Cracks at Eggcrates and Sludge Pile Region)

In order to determine a CM leakage limit for axial ODSCC cracks at eggcrates and in the sludge pile, the maximum depth of a "long" OD crack that will not burst at the accident-induced differential pressure will be determined.

Use part-throughwall crack correlation, Reference 4.2 section 5.1.4:

$\sigma_c := 0.0705$ Coefficient Uncertainty

$h_{eff} := 50\%$ Initial Guess at effective depth

$L_{eff} := 3 \cdot in$ Effective Length ("Long" crack assumed, with no uncertainty)

Given

$$\Delta P_{ACC} = 0.58 \cdot (S_y + S_u) \cdot \frac{t_{wall}}{R_i} \cdot \left(1.104 - \frac{L_{eff}}{L_{eff} + 2 \cdot t_{wall}} \cdot h_{eff}\right)$$

$h_{LL} := Find(h_{eff})$ $\qquad$ $h_{LL} = 84.03\,\%$ $\qquad$ Structural Limit at Accident-Induced Pressure Difference

Determine the SRSS uncertainty component due to material strength uncertainty:

Given

$$\Delta P_{ACC} = 0.58 \cdot (S_y + S_u - Z \cdot \sigma_M) \cdot \frac{t_{wall}}{R_i} \cdot \left(1.104 - \frac{L_{eff}}{L_{eff} + 2 \cdot t_{wall}} \cdot h_{eff}\right)$$

$Z\sigma_{hM} := h_{LL} - Find(h_{eff})$ $\qquad$ $Z\sigma_{hM} = 0.0000\,\%$

Determine the SRSS uncertainty component due to burst correlation coefficient uncertainty

Given

$$\Delta P_{ACC} = 0.58 \cdot (S_y + S_u) \cdot \frac{t_{wall}}{R_i} \cdot \left(1.104 - Z \cdot \sigma_c - \frac{L_{eff}}{L_{eff} + 2 \cdot t_{wall}} \cdot h_{eff}\right)$$

$Z\sigma_{hR} := h_{LL} - Find(h_{eff})$ $\qquad$ $Z\sigma_{hR} = 9.2972\,\%$

The SRSS uncertainty, exluding NDE technique and analyst errors, is:

$$h_{RED} := h_{LL} - \sqrt{(Z\sigma_{hM})^2 + (Z\sigma_{hR})^2} \qquad h_{RED} = 74.729\,\%$$

The corresponding NDE depth from ETSS 96008.1 is:

$$h_{NDE} := 0.74 \cdot h_{RED} + 18.57\% \qquad h_{NDE} = 73.87\,\%$$

The corresponding CM limit, to have confidence that an axial crack at the expansion transition will not leak, is:

$$RMSE := 21.34\%$$

$$h_{CMAL} := h_{NDE} - Z \cdot RMSE \qquad h_{CMAL} = 46.5\,\%$$

There is additional conservatism in this calculation since the maximum NDE depth is used against the CM criteria, whereas the burst correlation is based on the effective depth.

Degradation Mechanism # 5 - Circumferential Cracking at TTS Expansions

First determine the structural limit in terms of PDA with no uncertainties by manipulating Eq'n 5-21 in the EPRI *Flaw Handbook*:

$$PDA_{STR} := \left[0.57326 - \frac{\Delta P_{IA} \cdot R_m}{(S_y + S_u) \cdot t_{wall}}\right] \cdot 0.35281^{-1} \qquad PDA_{STR} = 71.4634\,\%$$

The structurally limiting PDA is less than 75%, so the selection of Eq'n 5-21 was appropriate.

Now determine the structural PDA, reduced for material and relational error uncertainties:

$$\sigma_{PN} := 0.007503$$

$$PDA_{RED} := \left[0.57326 - 1.383 \cdot \sigma_{PN} - \frac{\Delta P_{IA} \cdot R_m}{(S_y + S_u - Z \cdot \sigma_M) \cdot t_{wall}}\right] \cdot 0.35281^{-1} \qquad PDA_{RED} = 68.5222\,\%$$

Circumferential ODSCC Condition Monitoring Limit:

From ETSS 21410.1, the PDA integrity assessment data is insufficient to derive a correlation. Although the correlation coefficient just meets the requirement for 28 data points, the data is not well spread out and insufficient data is present near the structural limit. To obtain a condition monitoring limit, the length NDE measurement parameter will be used, with the PDA calculated assuming that the crack is through-wall.

For Ginna SG tubing, the structurally limiting circumferential crack length is calculated using the PDA and tube OD as:

$$L_{STR} := PDA_{STR} \cdot \pi \cdot OD_{tube} \qquad L_{STR} = 1.6838\,in$$

The corresponding NDE length, using the correlation from ETSS 21410.1, is:

$$L_{NDE} := \frac{L_{STR} - 1.07 \cdot in}{0.74} \qquad L_{NDE} = 0.8295\,in$$

This is less the the 90/50 standard error in assessing the length; therefore, no reasonable condition monitoring limit can be established analytically for circumferential ODSCC.

Condition monitoring for circumferential ODSCC indications at the TTS expansion will be by in-situ pressure testing.

Circumferential PWSCC Condition Monitoring Limit:

From ETSS 20510.1, the PDA integrity assessment data has a correlation coefficient of 0.878, which is sufficient for the number of data points to have 95% confidence that the correlation exists.

$PDA_{NDE} := 0.95 \cdot PDA_{RED} + 3.63\%$ $\qquad$ $PDA_{NDE} = 68.7261\,\%$

$RMSE := 8.27\%$ $\qquad$ From ETSS 20510.1 technique performance

The condition monitoring limit for PWSCC, excluding analyst error which must be determined is therefore:

$PDA_{CM} := PDA_{NDE} - Z \cdot RMSE$ $\qquad$ $PDA_{CM} = 58\,\%$

Ginna Station 2002 RFO
SGB Secondary-Side Visual Inspection Plan

PURPOSE

This inspection plan details items to be inspected during the 2002 refueling outage on Steam Generator B (EMS01B), including items in the steam drum and u-bend regions, and non-FOSAR inspection activities at the tubesheet.

This inspection plan is an outage-specific attachment to GMS-43-43-INTERNAL, which is the governing procedure for secondary-side internal inspections. Inspection guidance, including what to look for, is included in that procedure. Document all findings, including no degradation findings, in Attachment 5 of GMS-43-43-INTERNAL. Also document the camera used for each inspection, if applicable.

Note that the final portion of this inspection plan is for inspection at the tubesheet. This inspection is to occur after the secondary handholes have been removed, but before sludge lancing.

EQUIPMENT

1. 25' Videoprobe with assorted tip adaptors and Decron conduit
2. 2 mm fiberscope (semi-rigid) with gripper for in-bundle inspection / scale sample removal
3. Ca-Zoom PTZ camera
4. Pole camera(s)
5. Digital camera (KODAK DC5000)
6. Extenda-Cam
7. FOSAR Car
8. Lanyards
9. Recorder (Digital8 or Hi8, VHS)
10. Tapes and other supplies as per GMS-43-43-INTERNAL

INSPECTION PLAN

Upper Steam Drum Visual Inspection (GMS-43-43-INTERNAL, section 7.1):

1.0 Initial condition WR water level to be set at _____ inches. [ ]

1.1 Inspect the seven (7) steam flow restrictor venturis [Item 1]. [ ]

1.2 Inspect the venturi flow restrictor retainer plate, and the six (6) capscrew retainers [Item 2]. [ ]

1.3 Inspect the seal skirt to secondary head weld [Item 3]. [ ]

1.4 Inspect the seal skirt to secondary deck weld [Item 4]. [ ]

1.5 Inspect a random selection of at least 20% (18) of the secondary separator outlet holes [Item 5]. [ ]

1.6 Inspect a random selection of at least 20% (18) of the secondary separator to secondary deck fillet welds [Item 6]. [ ]

1.7 Inspect a random selection of at least 20% (68) of the secondary separator vent holes [Item 7]. [ ]

1.8 Inspect a random selection of at least 20% (18) of secondary separator skimmer slots [Item 8]. [ ]

1.9 Inspect as many of the secondary separator inlet swirl vane to bottom plate welds as practical with available equipment [Item 9]. [ ]

1.10 Inspect as many of the secondary separator inlet swirl vane to body welds as practical with available equipment [Item 10]. [ ]

1.11 Inspect all secondary deck door nut locking tabs and lock wires [Item 11]. [ ]

NOTE: It may be easier to inspect some or all of the primary separator heads during the Lower Steam Drum Inspection (GMS-43-43-INTERNAL, section 7.3).

1.12 Inspect 10% (9) primary separator cyclone heads and outer cylinders (including upper lip, flow holes, and spacers) [Items 12,15]. [ ]

Lower Steam Drum Inspection (GMS-43-43-INTERNAL, section 7.3):

2.0 Maintain WR level at previously established value. [ ]

2.1 Verify no obvious damage to secondary separator drain tubes [Item 13]. [ ]

2.2 Inspect leading edge of accessible secondary separator inlet swirl vanes [Item 14]. [ ]

2.3 Inspect accessible drain tube retention clips, and access ladder supports. [ ]

2.4 Inspect the top side of the primary deck for loose parts, deposits, and other abnormalities. Also check the condition of the outside diameter of accessible primary separator riser tubes, deck stiffener plates, and primary deck peripheral weir [Items 16, 17, 18]. [ ]

2.5 Inspect the condition of primary deck support lugs accessible from access tunnel [Item 20]. [ ]

2.6 Open primary door in accordance with step 7.4 of GMS-43-43-INTERNAL. Secure deck door in closed position with dog nuts hand tight until entry into U-bend required. [ ]

2.7 Lower WR water level to _____ inches in accordance with step 7.3.4 of GMS-43-43-INTERNAL. [ ]

2.8 Inspect accessible portions of camera track and supports (below primary deck) from gooseneck cutout access [Item 23]. [ ]

2.9 Inspect accessible J-tubes from gooseneck cutout access, including welds [Item 22]. [ ]

2.10 Inspect the shroud area below accessible J-tubes for signs of flow-assisted corrosion. This will typically be evident by a red or orange discoloration [Item 24]. [ ]

U-Bend Area Inspection (GMS-43-43-INTERNAL, section 7.5):

3.0 Lower WR water level to _____ inches in accordance with step 7.5.1 of GMS-43-43-INTERNAL. [ ]

3.1 Inspect the general condition of the U-bend assembly tie tubes and tie-tube lugs [Items 25,26] [ ]

3.2 Inspect the U-bend arch bars, clamping bars, and J-tabs [Item 27]. [ ]

3.3 Inspect a sample of J-tab to tube contact points, looking at deposit loading in particular. Note that the J-tab contact surface is curved [Item 28]. [ ]

3.4 Inspect both U-bend restraint / jaw bar assemblies [Item 29]. [ ]

3.5 Inspect primary deck lug welds [Item 30, inside shroud]. [ ]

3.6 Inspect feedwater header support welds [Item 31, inside shroud]. [ ]

3.7 Inspect shroud slider to shroud extension weld [Item 32]. [ ]

3.8 Inspect a 20% random sample (17) of the primary separator to primary deck welds [Item 33]. [ ]

3.9 Inspect recirculation nozzle penetration to u-bend [Item 34]. [ ]

3.10 Inspect the six (6) maintenance deck attachment lugs [Item 35]. [ ]

3.11 Using the 25' videoprobe and decron conduit, observe the upper lattice grid to assess deposit loading, particularly on the hot leg side. [ ]

3.12 Using the 25' videoprobe and decron conduit, observe the saddle bar assemblies on at least one end of the tube bundle. [ ]

3.13 Using the in-bundle probe, assess the deposit loading condition in two random columns in the central portion of the hot leg (between the 2 1/4° and 14° fan bar stacks). If possible, attempt to retrieve a sample of scale using the mini-gripper on the probe. [ ]

Tubesheet Inspection

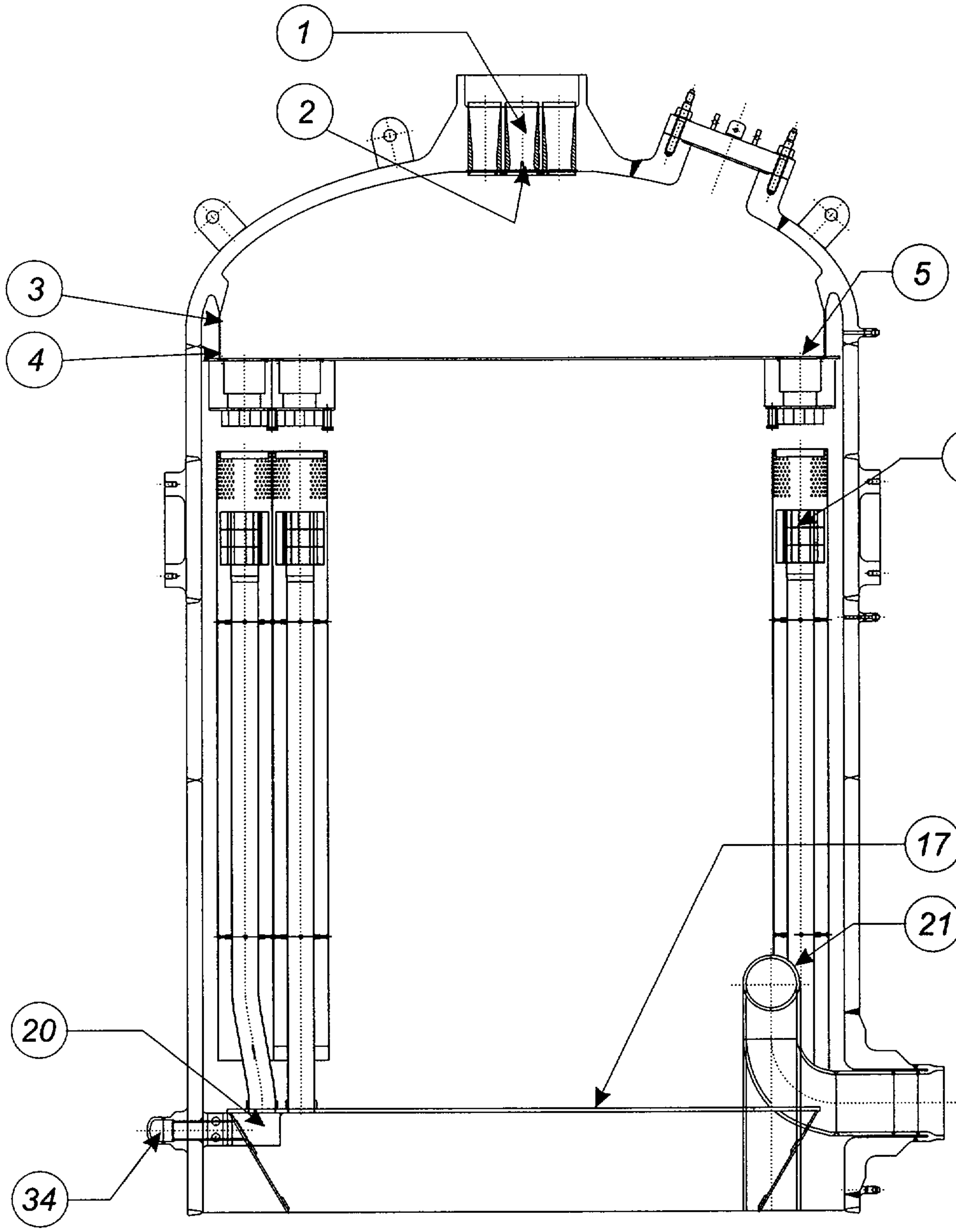
4.0 Steam generator has been drained and secondary handholes removed. [ ]

4.1 Using the in-bundle probe, assess the sludge loading in the hot leg (two columns, centrally located) and cold leg (two columns, centrally located). If possible, attempt to retrieve a sample of scale using the mini-gripper on the probe. [ ]

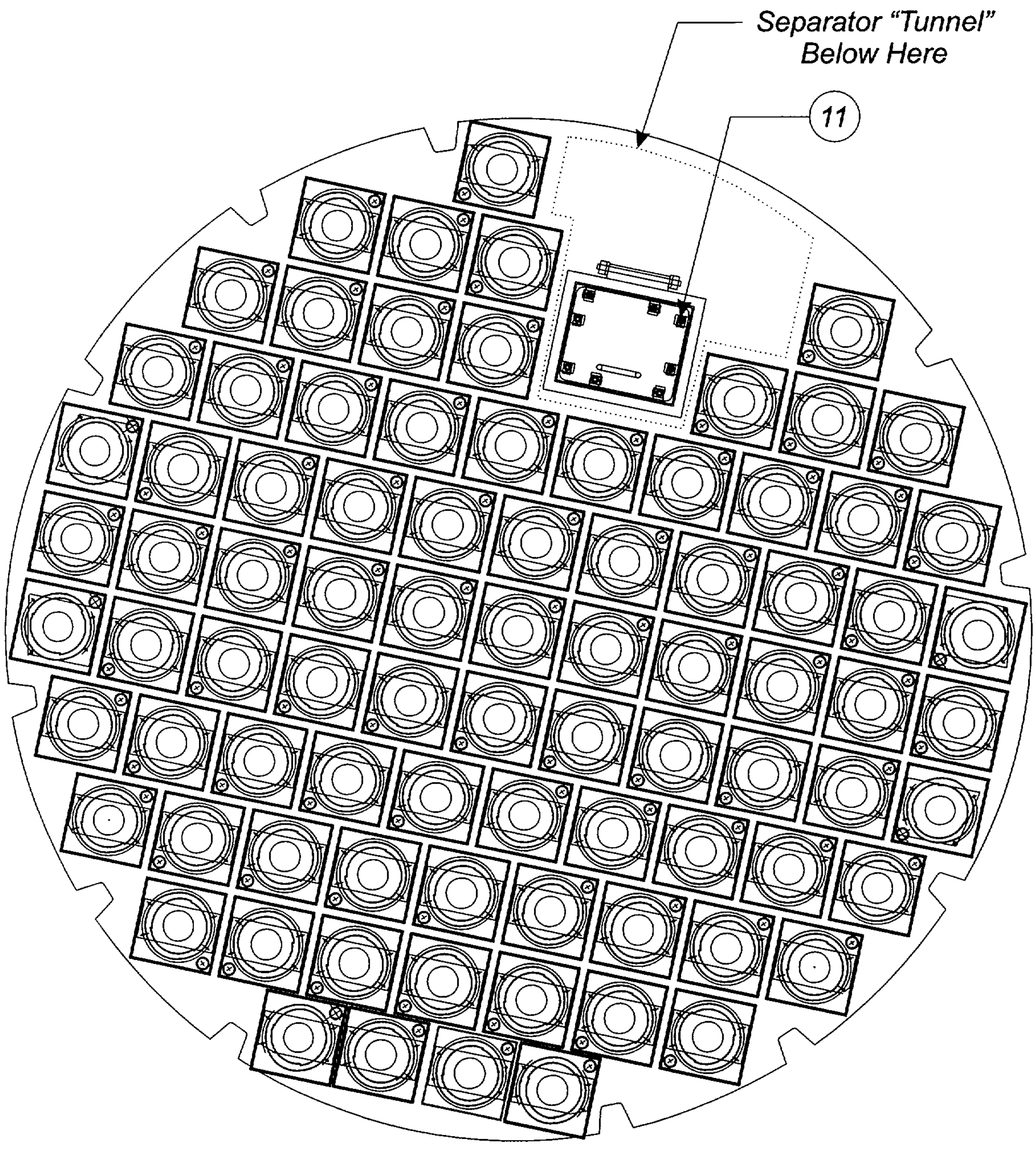
4.2 Using the in-bundle probe, observe the underside of the first lattice grid in the hot leg (two columns, centrally located) and the cold leg (two columns, centrally located). [ ]

4.3 Using the FOSAR car, inspect at least two (2) shroud support lugs and two (2) shroud pins. [ ]

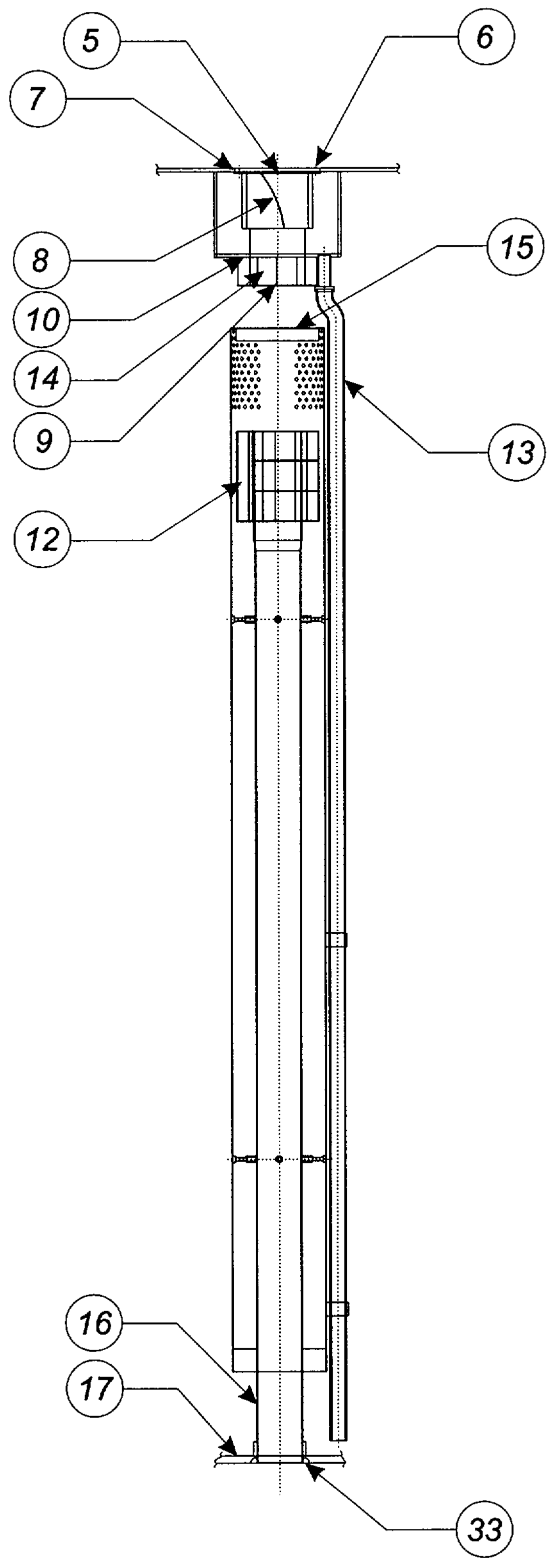
STEAM DRUM



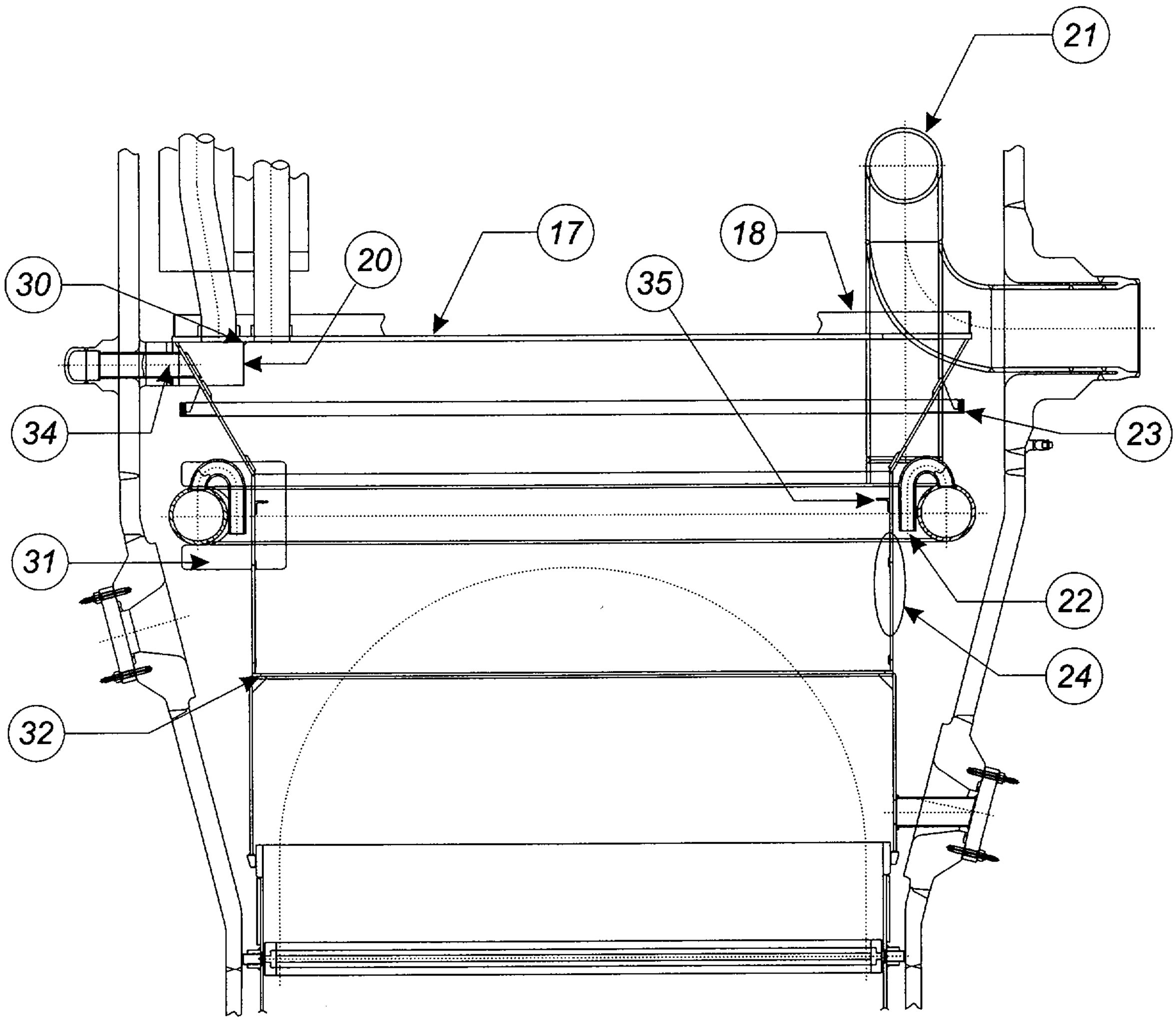
SECONDARY SEPARATOR DECK LAYOUT



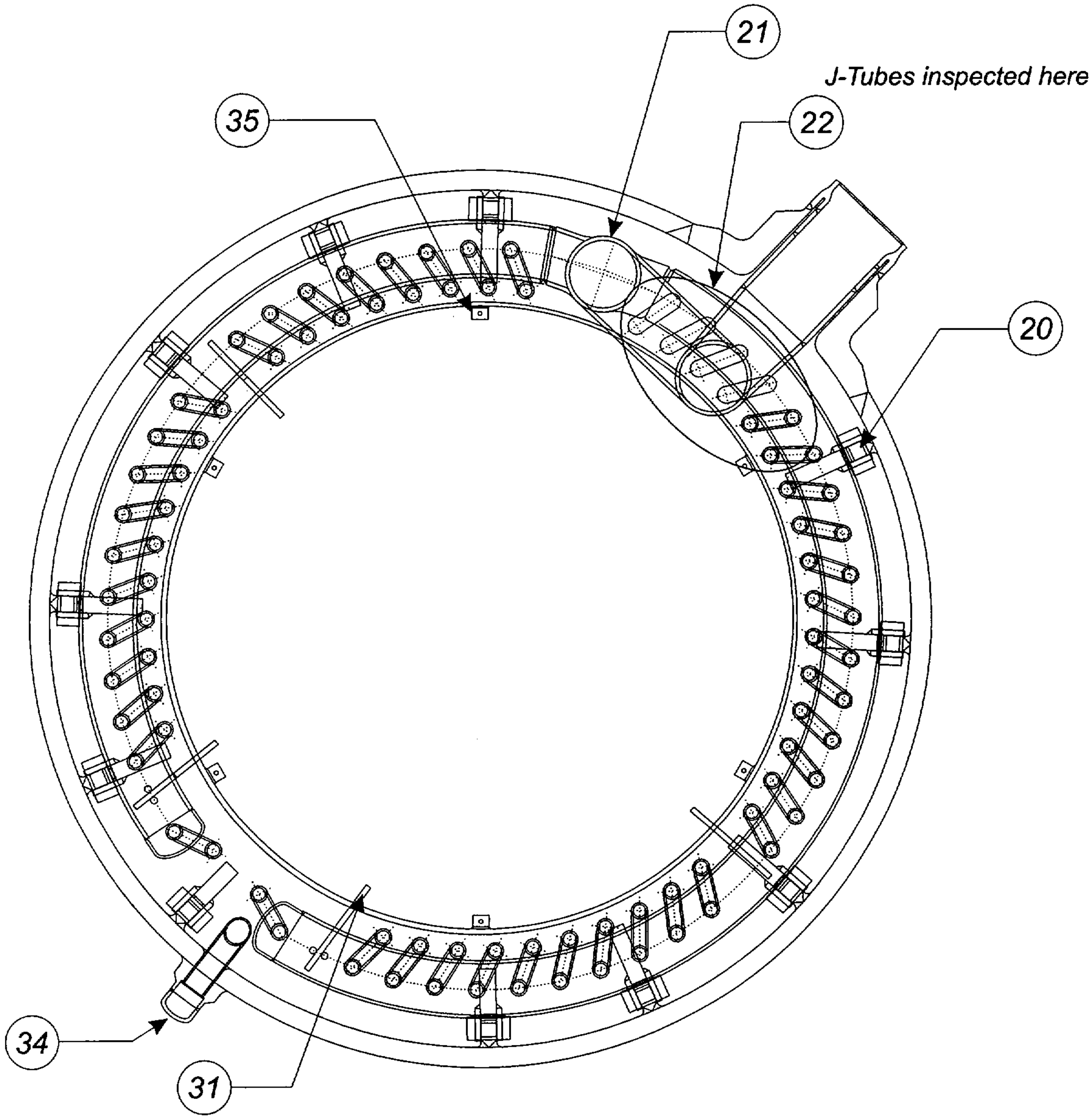
MODULAR PRIMARY / SECONDARY SEPARATOR PAIR



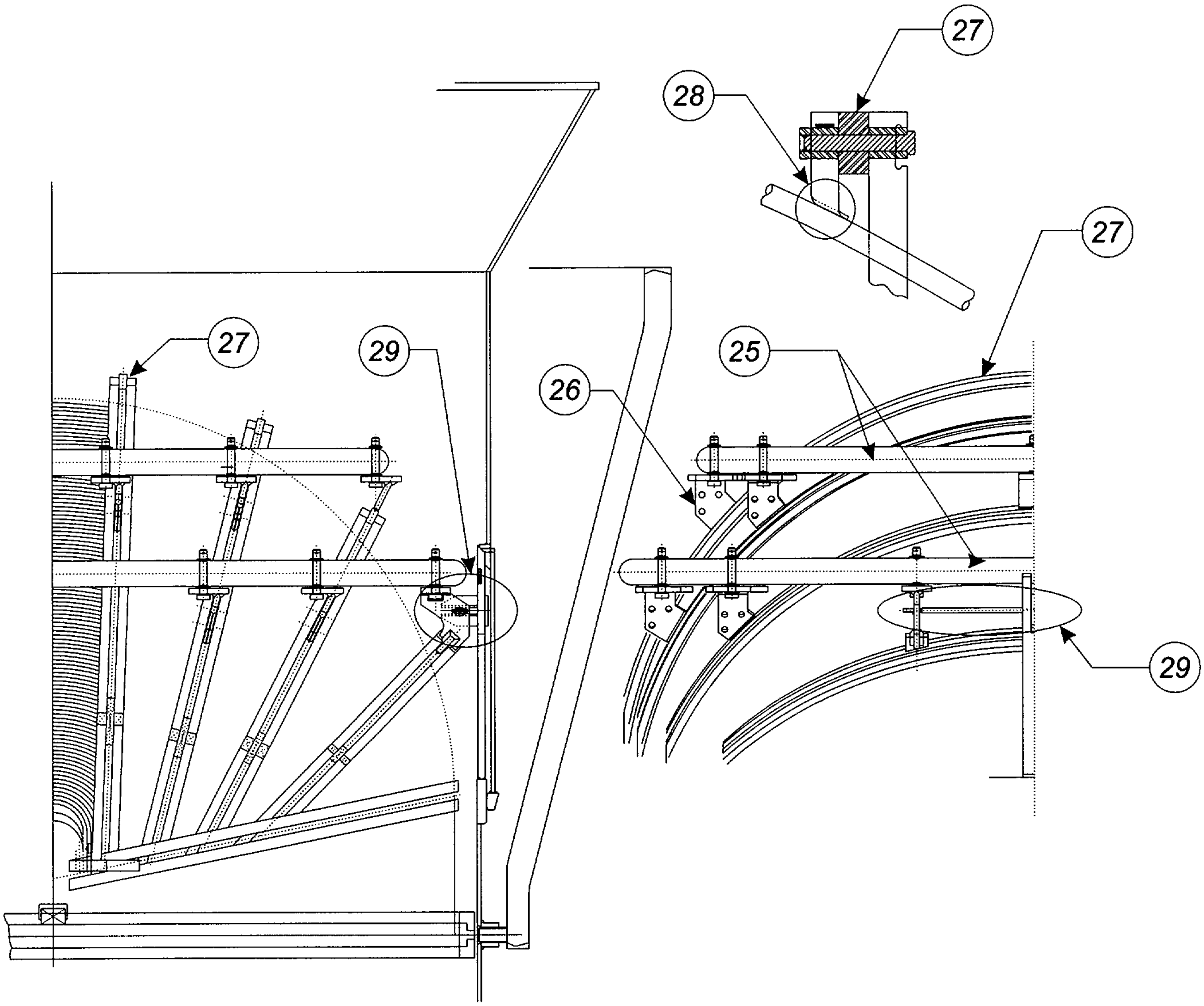
FEEDRING / U-BEND SIDE VIEW



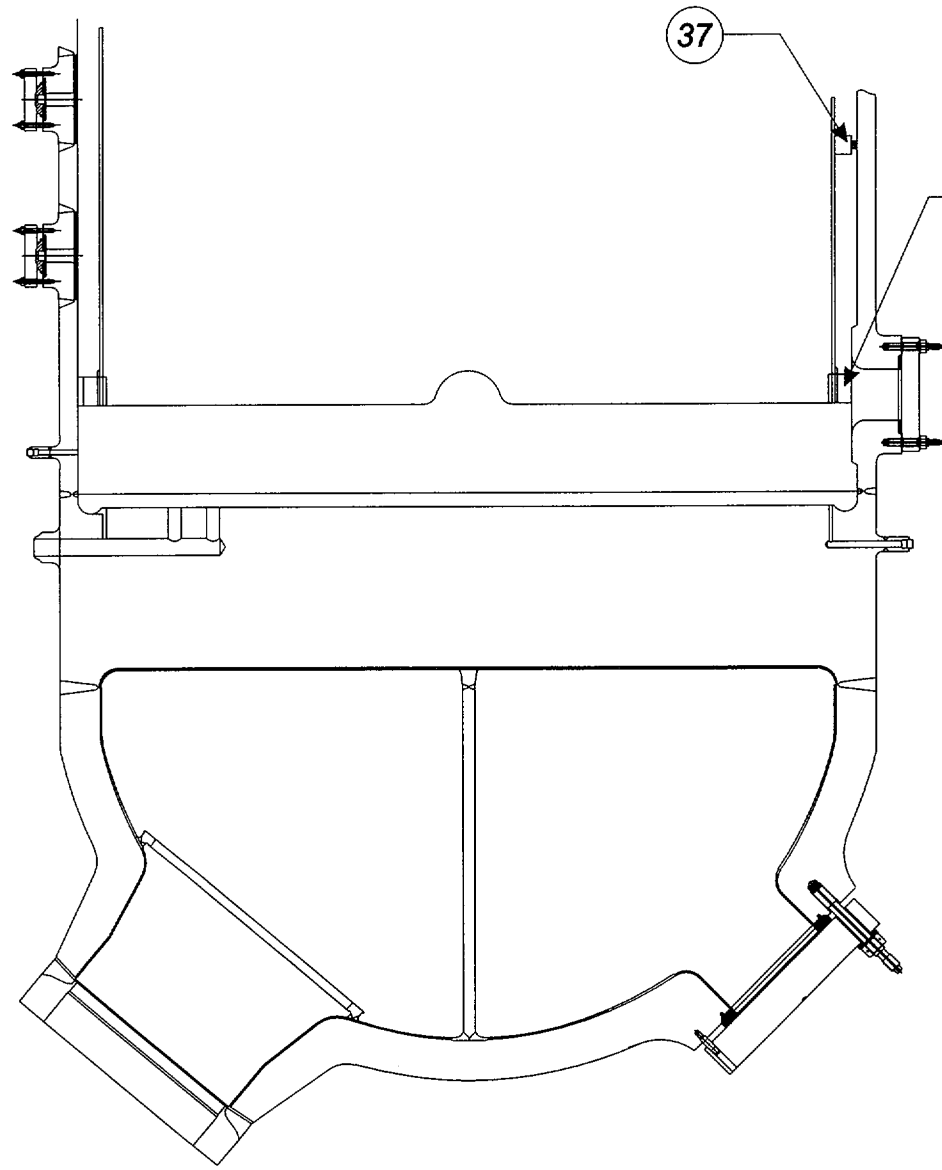
FEEDRING TOP VIEW



U-BEND SUPPORTS



LOWER SHELL



Attachment II

R.E. Ginna Nuclear Power Plant

2002 Steam Generator Inspection Summary

1.0 Introduction

Westinghouse Nuclear Services Business Unit Steam Generator Services Department performed eddy current examination of the steam generator tubing at Rochester Gas and Electric (RG&E) Ginna Nuclear Power Station during March 2002. The purpose of the examination was to assess the condition of the steam generators, to identify tubes requiring repair and to provide the information necessary to fulfill plant Technical Specification requirements.

The replacement steam generators, A (BWI #34) and B (BWI #35), were designed and manufactured by Babcock and Wilcox International (BWI). Each steam generator contains 4,765 U-bend Alloy 690 tubes, with nominal dimensions of 3/4" O.D. X .043" wall thickness.

The examination program included multi-frequency bobbin testing for indications of degradation, tube to tube proximity, loose parts, deposits and dents. Motorized pancake/plus point testing for detection of axial and circumferential cracking and further evaluation of tube proximity and detected bobbin indications were also performed.

Westinghouse performed eddy current examinations in accordance with, Rochester Gas and Electric Procedure Number ET-109 "Digital Eddy Current Examination of Alloy 690 Steam Generator Tubing", Revision 5. All examinations are in compliance with the United States Nuclear Regulatory Commission Regulatory Guide 1.83 and the Rochester Gas and Electric Ginna Station Technical Specifications.

Eddy Current Data Analysis was performed in accordance with the Rochester Gas and Electric Steam Generator Data Analysis Guidelines dated 3/20/02 with Guidelines Change Forms 2002-1, 2002-2 and 2002-3. Westinghouse, Verner & James and DESI personnel performed independent manual primary analysis for all bobbin and MRPC data. Zetec performed independent secondary analysis utilizing computer data screening (CDS) for bobbin data and manual analysis for MRPC data. Representatives of Westinghouse and Zetec performed resolution analysis. A resolution team consisted of a primary resolution person from Westinghouse and a secondary resolution person from Zetec. RG&E provided an independent QDA from Progress Energy as oversight to the analysis activities in accordance with EPRI Guidelines.

The ST200 Database Management System software managed eddy current examination results in accordance with Westinghouse Procedure SGMS 2.2.1 GEN-11 "Steam Generator Data Management", Revision 6. This procedure utilized Ginna site-specific checklists and configuration forms to document guidelines, closeout and decision processes.

The EddyNet Inspection Management System (EIMS) was used by Zetec as a secondary data management system. EIMS utilized Ginna site-specific checklists and configuration forms to document guidelines, closeout and decision processes. The outputs of both systems were compared to ensure completion of testing and data accuracy for both systems.

2.0 Summary

A tube end to tube end inspection was performed on approximately 50% of the tubes in the Rochester Gas and Electric Ginna Station steam generators during the 2002 refueling outage. This inspection was to identify wall loss indications, tube-to-tube contact, loose parts detection and any manufacturing anomalies. Special attention was given to all peripheral tubes for tube-to-tube contact and the presence of loose parts. Eddy current techniques included bobbin coil and various rotating coil technologies to further investigate bobbin indications and other suspect regions. Table 2-3 summarizes the steam generator eddy current examinations performed during this refueling outage.

2.1 Steam Generator "A" BWI #34

The primary inspection program consisted of:

Bobbin examination: ~50% of tubes full length plus peripheral tubes for tube to tube proximity indications (2487 tubes)

MRPC examination: ~20% of top of tubesheet expansion transition, gripper locations and preservice manufacturing non-conformances (983 tubes)
20% of rows 1 & 2 U-bend (24 tubes)
13 tubes identified as potential tube-to-tube proximity

X-Probe examination: 34 tubes full length; 133 tubes 01H through hot leg tube end

Additional inspection programs consisted of:

MRPC examination: 2 tubes; top of tubesheet
25 tubes; freespan

No tubes were removed from service.

Two hundred and forty-four (244) indications attributable to the manufacturing process (MBM) were identified. These indications when compared to the pre-service data showed no change. The MBM's were broken into four categories:

Category 1: MBM's with a voltage ≥2.5 volts and <5.0 volts when measured from 140 kHz absolute.
Category 2: MBM's ≥ 5.0 volts when measured from 140 kHz absolute.
Category 3: MBM's less than the 2.5 volt calling criteria with a previous reportable (i.e., ≥ 2.50 Vpp) reading.
Category 4: MBM's with a > 0 percent thru wall signal measured from the 550/140 kHz differential mix

Historical data had identified thirteen (13) tubes as having potential tube-to-tube contact, these tubes were scheduled for combination pancake / plus point motorized probe (MRPC) testing. During the bobbin coil examination a total of ten (10) from the original thirteen (13) tubes were identified with potential tube-to-tube proximity using the bobbin coil (PRO). The 2002 outage MRPC inspections identified and confirmed all previous thirteen of the tubes with tube-to-tube proximity signals (PRS). No evidence of wear was detected. There was no evidence of tube to tube proximity location or extent change, when these tubes were compared to the prior historical data. In addition to the tube to tube proximity MRPC inspections at the previously identified locations, the bobbin coil data was compared to historical data in all possible peripheral tube to tube proximity tubes.

Twenty-five (25) tubes were identified with INF or INR calls. For the INF calls, the location listed in the historical data was not properly referenced and the indication was associated with the correct location in the current inspection. The tube identifications and indication locations were verified in the historical data. This was typically attributed to the auto locate algorithms having difficulty in the regions where the number of fan bars were changing and the fan bar and collector bar were not easily distinguished. The INR tubes show a low frequency response that was initially thought to be due to a potential loose part. However, the signal was verified to be attributable to the probes sensing one another when they passed one another in the dual probing process. Changes in relative start positions and speeds were implemented to minimize the occurrence of this anomalous response. A representative sample of these tubes were retested, and an INF was reported to document the lack of the anomalous response.

Forty-five (45) tubes were identified with dings (free span dents) or dents (dents at supports). Of the reported dings, 15 are new listings. 20 of the 34 dings are in the region spanning 08H to 08C. Of the reported dents, 10 are new listings. All of the dents are in the region spanning 08H to 08C. None of the dents or dings exhibit growth when compared to historical data.

Table 2-1 summarizes all indications reported as a result of this inspection. Differences between the tabulation and the database distribution report are noted. This is due to the data base distribution report counting all occurrences of the indication in the database, including for multiple tests. The tabulation eliminates the double entries due to multiple tests.

Table 2-1. Summary of reported indications for S/G-A.

Indication Code	Number of Tubes	Number of Indications
MBM (≥2.50 Vpp MBM <5.00 Vpp with no P1 % TWD response)	145	167
MBM (5.00 Vpp ≤ MBM with no P1 %TWD response)	50	51
MBM (≤ 2.50 Vpp with no P1 % TWD response)	8	8
MBM (With P1 response ≥ 0%)	16	18
MBC (Manufacturing Burnish Mark Confirmed By RPC)	14	15
PRO (Proximity effect detected by bobbin)	10	21
PRS (Proximity effect detected by RPC)	13	28
INF (Indication Not Found)	9	10
INR (Indication Not Reportable)	20	20
DNG (Ding)	32	34
DNT (Dent)	15	16
DEP (Deposit Bobbin/MRPC)	26/7	27/7

2.2 Steam Generator "B" BWI #35

Bobbin examination: ~50% of tubes full length plus peripheral tubes for tube to tube proximity indications (2486 tubes)

MRPC examination: ~20% of top of tubesheet expansion transition, gripper locations and preservice manufacturing non-conformances (957 tubes)
20% of rows 1 & 2 u-bend (24 tubes)
12 tubes; identified as potential tube to tube proximity

Additional inspection programs consisted of:

MRPC examination: 21 tubes; top of tubesheet
22 tubes; freespan

Bobbin examination: 90 tubes in S/G-B for FME inspection

No tubes were removed from service.

Two hundred and fifty-five (255) indications attributable to the manufacturing process (MBM) were identified. These indications when compared to the pre-service data showed no change. The MBM's were broken into four categories:

Category 1: MBM's with a voltage ≥2.5 volts and <5.0 volts when measured from 140 kHz absolute.
Category 2: MBM's ≥ 5.0 volts when measured from 140 kHz absolute.
Category 3: MBM's less than the 2.5 volt calling criteria with a previous reportable (i.e., ≤ 2.50 Vpp) reading.
Category 4: MBM's with a > 0 percent thru wall signal measured from the 550/140 kHz differential mix

Historical data had identifies twelve (12) tubes as having potential tube-to-tube contact, these tubes were scheduled for combination pancake / plus point motorized probe (MRPC) testing. During the bobbin coil examination a total of nine (9) tubes were identified with potential tube-to-tube proximity using the bobbin coil (PRO). The 2002 outage MRPC inspections identified and confirmed all twelve of the tubes with tube-to-tube proximity signals (PRS). No evidence of wear was detected. There was no evidence of tube to tube proximity location or extent change, when these tubes were compared to the prior historical data. In addition to the tube to tube proximity MRPC inspections at the previously identified locations, the bobbin coil data was compared to historical data in all possible peripheral tube to tube proximity tubes .

Eleven (11) tubes were identified with INF or INR calls. For the INF calls, the location listed in the historical data was not properly referenced and the indication was relocated in the current inspection. The tube identifications and indication locations were verified in the historical data. This was typically attributed to the auto locate algorithms having difficulty in the regions where the number of fan bars were changing and the fan bar and collector bar were not easily distinguished. The INR tubes show a low frequency response that was initially thought to be due to a potential loose part. However, the signal was verified to be attributable to the probes sensing one another when they passed one another in the dual probing process. Changes in relative start positions and speeds were implemented to minimize the occurrence of this anomalous response. A representative sample of these indications were retested, and an INF was reported to document the lack of the anomalous response.

Fifty-nine tubes(59) were identified with dings (free span dents) or dents (dents at supports). Of the reported dings, 31 are new listings. 16 of the 54 dings are in the region spanning 08H to 08C. Of the reported dents, 11 are new listings. 17 of the dents are in the region spanning 08H to 08C; one is associates with 02H. None of the dents or dings exhibit growth when compared to historical data.

Table 2-2 summarizes all indications reported as a result of this inspection. Differences between the tabulation and the database distribution report are noted. This is due to the data base distribution report counting all occurrences of the indication in the database, including for multiple tests. The tabulation eliminates the double entries due to multiple tests.

Table 2-2. Summary of reported indications for S/G-B.

Indication Code	Number of Tubes	Number of Indications
MBM (2.50 Vpp ≤ MBM <5.00 Vpp with no P1 % TWD response)	139	163
MBM (5.00 Vpp ≤ MBM with no P1 %TWD response)	39	41
MBM (≤ 2.50 Vpp with no P1 % TWD response)	19	23
MBM (With P1 response ≥ 1%)	26	28
MBC (Manufacturing Burnish Mark Confirmed By RPC)	14	14
DSS (Distorted Support Signal)	2	2
NQS (Non-Quantifiable Signal)	1	1
INF (Indication Not Found)	5	5
INR (Indication Not Reportable)	6	6
PRO (Proximity effect detected by bobbin)	9	16
PRS (Proximity effect detected by RPC)	12	22
DNG (Ding)	42	52
DNT (Dent)	18	18
DEP (Deposit Bobbin/MRPC)	6/7	6/7

The total number of examinations and results for both S/G-A and S/G-B are summarized in Table 2-3. For graphical displays and detailed listings, refer to Sections 6 and 7 for Steam Generators A and B, respectively.

Table 2-3. Summary of examination and repairs for both Steam Generators.

Summary Of Steam Generator 2002 Outage Eddy Current Examination Of Ginna Steam Generator Tubing			
	Steam Generator		
	A	**B**	**TOTAL**
Tubes per Steam Generator	4765	4765	9530
Plugged At Start Of Outage	1	1	2
EXAMINATIONS:			
Bobbin probe tubes examined	2487	2486	4973
Bobbin probe tubes for FME	0	90	90
MRPC TTS H/L	983	957	1940
MRPC Proximity	13	12	25
MRPC rows 1&2	24	24	48
MRPC Diagnostic	27	43	70
X-Probe	167	0	167
RESULTS:			
MBM's ≥2.5 volts < 5.0 volts (Tubes)	145	139	284
MBM's ≥5.0 volts (Tubes)	50	39	89
MBM's < 2.5 volts – Historical (Tubes)	8	19	27
MBM with % on P1 (Tubes)	16	26	42
MBC (Tubes)	14	14	28
DSS (Tubes)	0	2	2
NQS (Tubes)	0	1	1
DNT (Tubes)	15	18	33
DNG (Tubes)	32	42	74
PRO Bobbin Signal (Tubes)	10	9	19
PRS MRPC Signal (Tubes)	13	12	25
DEP (Tubes – Bobbin/RPC)	26/7	6/7	32/14
REPAIRS:			
Plugged 2002	0	0	0
Repaired To Date:			
Total Plugged	1	1	2
Tubes In Service:	4764	4764	9528

3.0 Method

3.1 Test Equipment

Westinghouse GENESIS manipulators and dual guide tube fixture performed testing from the hot leg plenums in both steam generators. The vision system was used for independent position verification. All acquisition personnel were trained and qualified in the eddy current method and have been certified to a minimum of Level I, in addition acquisition personnel were trained and qualified to RG&E procedure ET-109 Rev 5.

Zetec MIZ-30 multi-frequency eddy current testers were used on 2 stations. HP workstations utilizing Zetec Eddynet98 acquisition software version 2.21 and an HP-UX operating system controlled the MIZ-30s and probe pushers. The GENISIS manipulator was controlled by the same workstation as the Miz-30. Acquisition stored the raw data on hard disk and then spooled the data to analysis data servers. The data were then transferred to rewritable optical disks and digital tape for permanent storage. Using a local area network (LAN) data analysis personnel accessed the data for reduction to results utilizing HP workstations and Eddynet98 analysis software version 2.21.

3.2 Test Frequencies

The test frequencies for the bobbin probes were 550, 280, 140, 35 kHz differential and absolute.
The test frequencies for 1 and2 Coil MRPC U-Bend probes were 400, 300, 100, 35 kHz absolute.
The test frequencies for 3 Coil MRPC straight body probes were 400, 300, 100, 35 kHz absolute.
The test frequencies for the X-Probe (T/R coils) were 400, 300, 200 and 100 kHz

3.3 Eddy Current Probes

Listed below are the description and functions of probes used at Ginna station.

Model	Description	Application	Data Base Acronym
A620MULC	Bobbin coil	Full length exams	ZBALC
A620MULC/C	Bobbin coil	Full length exams	ZBABP
A610MULC	Bobbin coil	Full length exams	ZBALC
A610MULC/C	Bobbin coil	Full length exams	ZBABP
B61011536S80	3 Coil MRPC 0.115 Pancake/+Point/0.80 Pancake	TTS and diagnostic exams	ZPSMR
B56011536	2 Coil MRPC 0.115 Pancake/+Point	Rows 1&2, proximity and diagnostic exams	ZPU2C
B58036	+Point	Rows 1&2 and diagnostic exams	ZPU1C
F1-610-01-XPROBE	X-Probe/Bobbin	Trial run, diagnostic comparison	RYAXP

3.4 Probe Speeds and Sample Rates

Probe speeds and sample rates are governed by the Rochester Gas and Electric Multi Frequency Eddy Current Inspection Set-Up Instructions Miz-30 (Section 1.4) for each test.

3.5 Calibration Standards

The calibration standards utilized for the examinations were supplied by RG&E.

ASME specifications applied to the manufacture of bobbin probe calibration standards. This flaw assortment permits set up of the spans and rotations.

MRPC standards were manufactured with various EDM notches to permit the set up of the spans and rotations to achieve the best possible detection. Additionally, standards representing the various support structures and proximity effects were utilized as applicable.

3.6 Data Analysis

Data were spooled from the acquisition stations to the analysis stations via a local area network (LAN). Two independent teams of Analysts analyzed the data using Zetec Eddynet98 version 2.21 software on an HP-UX operating system installed on HP workstations.

All analysis personnel were trained and qualified in the eddy current examination method and have been certified to a minimum of Level IIA and were qualified data analysts in accordance with EPRI Guidelines, Appendix G. In addition, all analysis personnel were qualified using a site-specific performance demonstration (SSPD). The SSPD consisted of both written and practical examinations. The written examination was pulled from a bank of questions on the R. E. Ginna analysis guidelines. The practical examinations consisted of data from the R.E. Ginna replacement steam generators and data from other plants with steam generators of similar design or with similar tubing where forms of potential degradation or anomalous signals were reported.

Lead analysts (eddy current Level III) from both parties, resolved discrepancies between the two sets of evaluation results. The removal of a potentially repairable indication from the database received the concurrence of two Lead Analyst personnel. The independent QDA reviewed the removed calls as well as a sampling of the data and analysis results.

Analysts were provided with feedback on their performance during the course of the examination per the EPRI Guidelines. This was accomplished using the Zetec Analyst Performance Tracking System software. Analysts reviewed their missed indications as well as a sampling of their overcalls.

3.7 X-Probe

The R/D Tech X-Probe was used on a sampling of tubes. The X-Probe combines a bobbin and a transmit/receive array. The bobbin probe is equivalent to the conventional impedance bobbin and was run at the same frequencies. The transmit/receive array of 48 coils is activated such that a number of axially and circumferentially sensitive sensing points are created. For display purposes, these are combined to create one axial and one circumferential channel for each frequency. The channels are displayed in a C-scan format and can be interrogated in either an axial or circumferential direction.

This testing was done to compare the outputs of the conventional impedance probes and the X-Probe for various anomalous conditions such as proximity, MBM and deposits. R/D Tech evaluated the data under a separate contract to RG&E. Results were transmitted to the ST2000 database management system for archival.

4.0 Reporting Acronyms

Various reporting acronyms were used during the course of the examination. The acronyms tabulated below are a subset of those in the guidelines, but reflect all of the acronyms used in the final examination report. These were used in the IND column, and the UTIL1 and UTIL2 fields of the report.

Table 4-1. Reporting codes used during the 2002 R. E. Ginna steam generator examination.

Codes Used In The IND Column Of The Report	
Acronym	**Description**
DEP	Deposit on OD of tube (sludge)
DNG	Dent not associated with a structure; reported at greater than or equal to 2.00 Vpp on 550/140 kHz differential mix
DNT	Dent at a support; reported at greater than or equal to 2.00 Vpp on 550/140 kHz differential mix
DSS	Distorted signal at a support; dispositioned by RPC
INF	Indication not found
INR	Indication not reportable
MBC	Manufacturing burnish mark confirmed by RPC
MBM	Manufacturing burnish mark; reported at greater than or equal to 2.50 Vpp on 140 kHz absolute channel unless there was a % TWD response on P1 or an historical MBM measured using that criterion
NDD	No detectable degradation
NDF	No degradation found – RPC test for special interest only
NQS	Non-quantifiable signal; dispositioned by RPC
PRO	Tube-to-tube proximity detected by bobbin; dispositioned by RPC
PRS	Tube-to-tube proximity detected by RPC
PVN	Permeability variation
RBD	Retest – bad data
RES	Tube restricted to passage of probe
RIC	Retest – incomplete test; required RPC test extent was not completed
Codes Used By Resolutions In The UTIL1 Field Of The Report	
CBP	Changed by previous
CMR	Confirmed by MRPC
DBH	Dispositioned by history data review
DBP	Dispositioned by pre-service data review
DMR	Dispositioned by MRPC
Codes Used By Resolutions In The UTIL2 Field Of The Report	
P1	% TWD > 0% on P1
WAR	Sized with respective wear scar standard
1	Tube anomaly
2	System noise
3	Deposit signal
4	Not flaw-like
5	Does not correlate
6	Does not meet reporting criteria
7	Mix residual
8	MRPC result is NDD
9	Acquisition message
10	Mischaracterized
11	Other (written explanation required if used)

5.0 Data Quality at Ginna Station

Steam generator condition monitoring and operational assessments use NDE results to assess the current condition of the tubing and to forecast the structural and leakage integrity of the unit over the next operating cycle. The Ginna station pre-outage degradation assessment details those damage mechanisms, which are known to exist at Ginna and those mechanisms to which BWI replacement steam generators are susceptible based on industry operating experience. The degradation assessment provides the bases for the selection of eddy current examination techniques that are appropriate to detect and characterize these forms of tube degradation.

The ECT techniques applied at Ginna station were qualified in accordance with Appendix H of the EPRI PWR Steam Generator Examination Guidelines, Revision 5. For each damage mechanism, an EPRI ETSS (Eddy current Technique Specification Sheet) is used to develop a Ginna Acquisition Technique Sheet (ACTS) and an Analysis Technique Sheet (ANTS) which are directly applicable to Ginna. For each technique the EPRI ETSS provides POD (probability of detection) values and sizing error where known, independent of the analysis process. In order for these values to be applied at Ginna it is necessary to ensure that the quality of ECT data is commensurate with that from the tubing used in the EPRI ETSS.

Prior to the Ginna 2002 inspection a sample of 1999 outage data was reviewed to quantify in-generator noise levels. Approximately 12 U-bends of plus point data per SG and approximately 25 hot leg roll transitions of plus point data per SG were evaluated. In addition, about 25 tubes of bobbin data per SG were analyzed for noise levels in the sludge pile area. The same sample sets from 1999 were used for the 2002 data, 2002 outage data was reviewed to quantify in-generator noise levels. As shown in the Tables 5-1 and 5-2, the average noise levels in the Ginna S/G's are either comparable to, or bounded by, the noise levels in the EPRI qualification data.

Table 5-1 1999 Ginna A&B S/G Data Quality Sampling

Area	**Probe & ETSS**	ETSS AVG VPP	**Ginna AVG VPP**	ETSS AVG VVM	**Ginna AVG VVM**	ETSS Worst VPP	**Ginna Worst VPP**	ETSS Worst VVM	**Ginna Worst VVM**
Ubend ID	**+Pt 965112**	1.06	**0.52**	0.36	**0.22**	1.60	**0.85**	0.61	**0.35**
ExpTrn OD	**+Pt 204091**	0.50	**0.24**	0.39	**0.11**	2.51	**0.36**	2.30	**0.19**
ExpTrn ID	**+Pt 967011**	0.57	**0.24**	0.19	**0.11**	1.57	**0.36**	0.48	**0.19**
SLG OD	**Bobbin 960081**	0.87	**0.34**	0.45	**0.07**	1.66	**0.58**	1.18	**0.13**

Table 5-2 2002 Ginna A&B S/G Data Quality Sampling

Area	Probe & ETSS	ETSS AVG VPP	Ginna AVG VPP	ETSS AVG VVM	Ginna AVG VVM	ETSS Worst VPP	Ginna Worst VPP	ETSS Worst VVM	Ginna Worst VVM
Ubend ID	+ Pt 965112	1.06	0.52	0.36	0.22	1.60	0.73	0.61	0.35
ExpTrn OD	+ Pt 204091	0.50	0.28	0.39	0.10	2.51	0.43	2.30	0.24
ExpTrn ID	+ Pt 967011	0.57	0.28	0.19	0.10	1.57	0.43	0.48	0.24
SLG OD	Bobbin 960081	0.87	0.34	0.45	0.07	1.66	0.52	1.18	0.17

There were a number of additional quality checks performed prior to and during the 2002 examination designed to ensure acceptable data quality. Each of the process steps is discussed below. A flow chart of this process follows this text.

5.1 Data Acquisition

All of the probes used at Ginna station were subjected to an on-site receipt inspection which included a calibration standard test to ensure that the probe was functioning properly. The probes were then logged into the Zetec Probe Inventory Management System which monitors probe usage during the inspection. The system reads the probe serial number from the calibration summary and prohibits data collection with probes which are not in the electronic database. In order to minimize extraneous noise in the eddy current data the Zetec MIZ-30 tester units were energized by a dedicated, conditioned power supply which is designed to minimize electrical noise and provide a constant voltage supply. In addition, the MRPC motor units were specifically designed to minimize extraneous noise by adding an electrical ground and shielding the motor from EMI.

5.3 Production Analysis

It was the responsibility of all personnel involved with the analysis process to identify conditions that inhibit the evaluation of the data. During the production analysis of the bobbin data, extraneous test variables that may create significant interference such as permeability, deposits, and mix residual were evaluated for their potential to mask a flaw and additional diagnostic tests (MRPC) were implemented where necessary. Dent as well as MBM indications were sampled with (MRPC). All analysts also checked the calibration standard response to ensure that the setup was in accordance with the applicable technique and that the sampling rate was within prescribed parameters.

For the U-Bend plus point exams, if the probe stopped rotating, data dropped out on 3 or more consecutive scan lines, or 3 or more noise spikes were identified in consecutive scan lines which the analyst believes would inhibit detection of relevant indications, the data was rejected.

5.4 Analyst Assigned to Monitor Data Quality During Analysis

An analyst was assigned to perform sampling of data quality. As with the analysts monitoring the data acquisition, these analysts were not burdened with production analysis responsibilities. Peak to peak and vertical maximum voltage measurements were recorded near the apex for all row 1 & 2 U-bends. If voltage values exceeded the average noise levels in the ETSS by more than 10%, the respective out of tolerance U-bends would be re-analyzed by a Level III Resolution analyst and deemed acceptable or retested. The review would have included the use of a circumferential average filter on the 300 KHz channel which provides a significant reduction of low frequency periodic noise associated with mechanical motion. This type of noise is also generated from tube wall thickness variations around the tube circumference as well as ovality from the bending process.

The data quality analyst also sampled plus point data quality data at the hot leg tubesheet expansion transition area. As with the U-bends, these tubes would have been identified, and re-analyzed by the Level III Resolution analyst and deemed acceptable or retested. At Ginna station there are no significant interferences from OD deposits and the dominant source of noise is the gradual geometry from the hydraulic expansion at the tubesheet interface.

Bobbin probe noise measurements were sampled and quantified in the freespan and support structures. Measurements were taken on the beginning and end tube on various calibrations.

Table 5-3 lists the applicable ETSS, their respective noise levels, and the reporting level (+10%) at Ginna Station.

Table 5-3 Applicable ETSS noise values and reporting levels.

Area	[redacted]	ETSS AVG VPP	[redacted]	ETSS AVG VVM	[redacted]
Ubend ID	[redacted]	1.11	[redacted]	0.28	[redacted]
ExpTrn OD	[redacted]	0.50	[redacted]	0.39	[redacted]
ExpTrn ID	[redacted]	0.57	[redacted]	0.19	[redacted]
SLG OD	[redacted]	0.87	[redacted]	0.45	[redacted]

5.4 Analyst Assigned to Monitor Data Quality During Analysis

An analyst was assigned to perform sampling of data quality. As with the analysts monitoring the data acquisition, these analysts were not burdened with production analysis responsibilities. Peak to peak and vertical maximum voltage measurements were recorded near the apex for all row 1 & 2 U-bends. If voltage values exceeded the average noise levels in the ETSS by more than 10%, the respective out of tolerance U-bends would be re-analyzed by a Level III Resolution analyst and deemed acceptable or retested. The review would have included the use of a circumferential average filter on the 300 KHz channel which provides a significant reduction of low frequency periodic noise associated with mechanical motion. This type of noise is also generated from tube wall thickness variations around the tube circumference as well as ovality from the bending process.

The data quality analyst also sampled plus point data quality data at the hot leg tubesheet expansion transition area. As with the U-bends, these tubes would have been identified, and re-analyzed by the Level III Resolution analyst and deemed acceptable or retested. At Ginna station there are no significant interferences from OD deposits and the dominant source of noise is the gradual geometry from the hydraulic expansion at the tubesheet interface.

Bobbin probe noise measurements were sampled and quantified in the freespan and support structures. Measurements were taken on the beginning and end tube on various calibrations.

Table 5-3 lists the applicable ETSS, their respective noise levels, and the reporting level (+10%) at Ginna Station.

Table 5-3 Applicable ETSS noise values and reporting levels.

Area	Probe & ETSS	ETSS AVG VPP	+ 10%	ETSS AVG VVM	+ 10%
Ubend ID	+Pt 965112	1.11	1.22	0.28	0.31
ExpTrn OD	+Pt 204091	0.50	0.55	0.39	0.43
ExpTrn ID	+Pt 967011	0.57	0.63	0.19	0.21
SLG OD	Bobbin 960081	0.87	0.96	0.45	0.50

5.5 Quality Assurance Checks During the Inspection

One QA engineer was assigned to monitor the ECT process during the inspection. A sampling of calibration summaries were reviewed and approved by QA prior to writing the information to the hard drive. Each manipulator position verification was independently confirmed by the independent tube verification system (vision system). QA confirmed the identification of the calibration standards was correct and spot-checked calibrations to ensure that the correct spans, rotations, and voltages were used. QA verified that the Probe Inventory Management System was up to date and accurate. Calibration setups were monitored to ensure that the correct spans and rotations were being used and also checked in generator data to verify probe speed and sample rate.

5.6 Data Management Checks During the Inspection

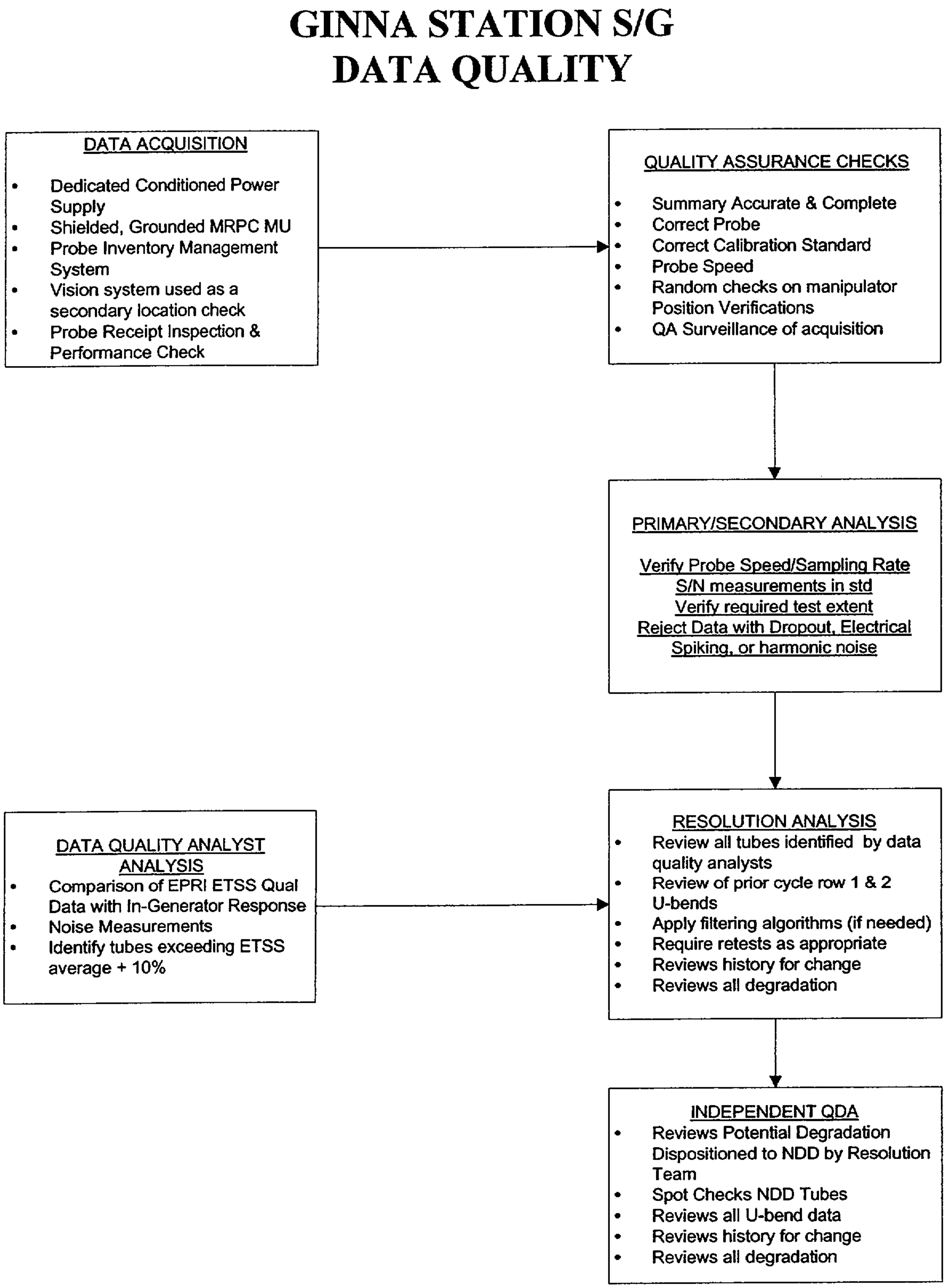
Two independent data management systems were used during the inspection. The Westinghouse ST2000 system was the primary system and the Zetec IMS was the secondary system. The results from each system were compared for consistency throughout the inspection.

Error checking was performed with each system_to assure that only valid reporting acronyms and locations were loaded to the final results. In addition a site-specific checklist for each data management system was formulated to identify the exact criteria before exam plan closeout, accuracy of reporting, and any tubes identified within the analysis guidelines framework to be plugged.

5.7 Summary

Several levels of data quality checks were performed during the 2002 outage. The noise levels in the Ginna SGs were found to be below the EPRI ETSS values. This assures the applicability of the techniques. Additionally, a number of other checks were performed in order to assure procedural compliance and ongoing data quality. Figure 5.1 illustrates the data quality checks performed.

Figure 5.1 Data quality checks performed at Ginna Station



Attachment III

R.E. Ginna Nuclear Power Plant

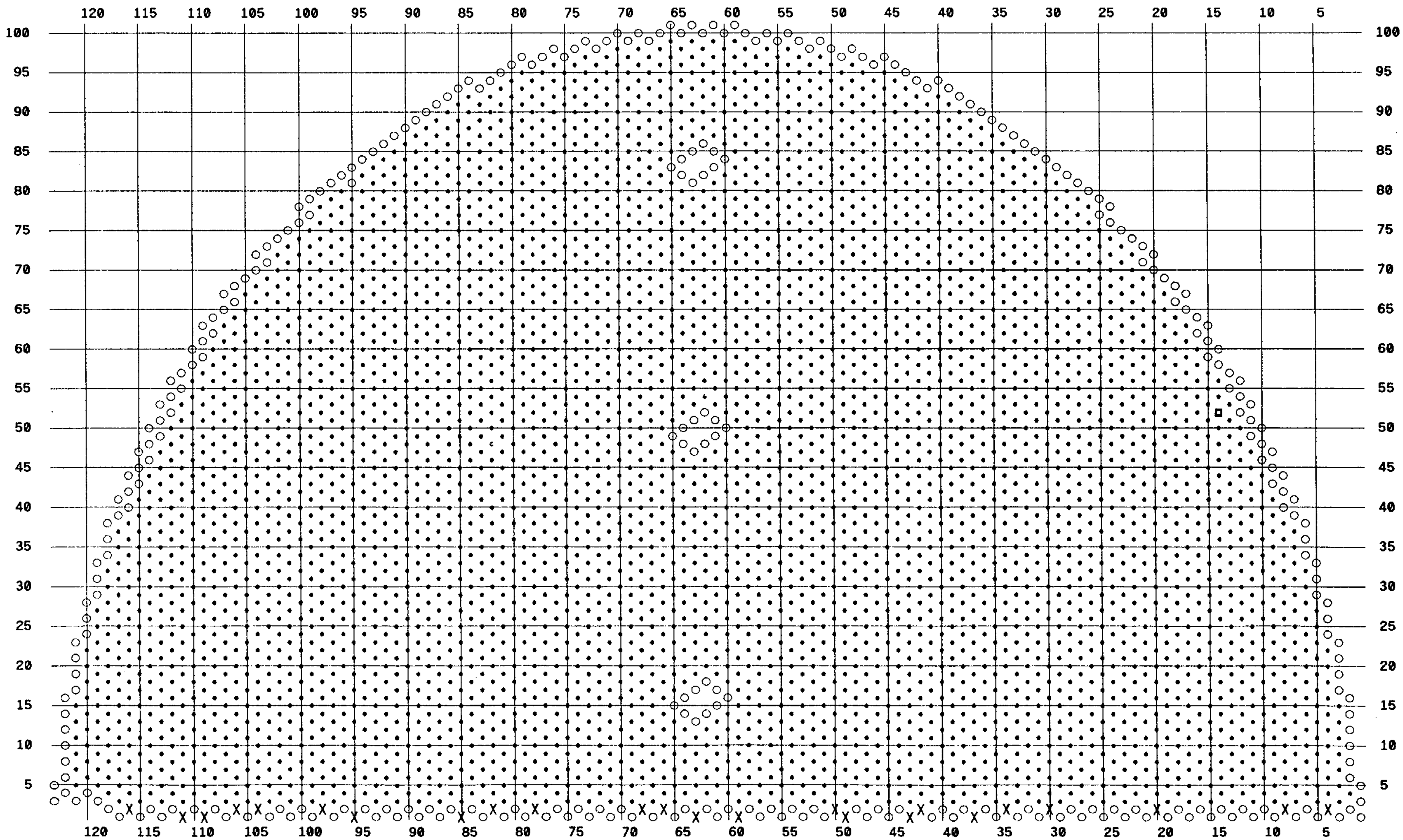
Steam Generator Tube Sheet Maps

SG - A U-BEND INSPECTION PROGRAM

Hot Leg Numbering View
R.E. Ginna RFO30 RGE RGEACL

X 24 TESTED U-BEND 08C - 08H

□ 1 PLUGGED TUBE



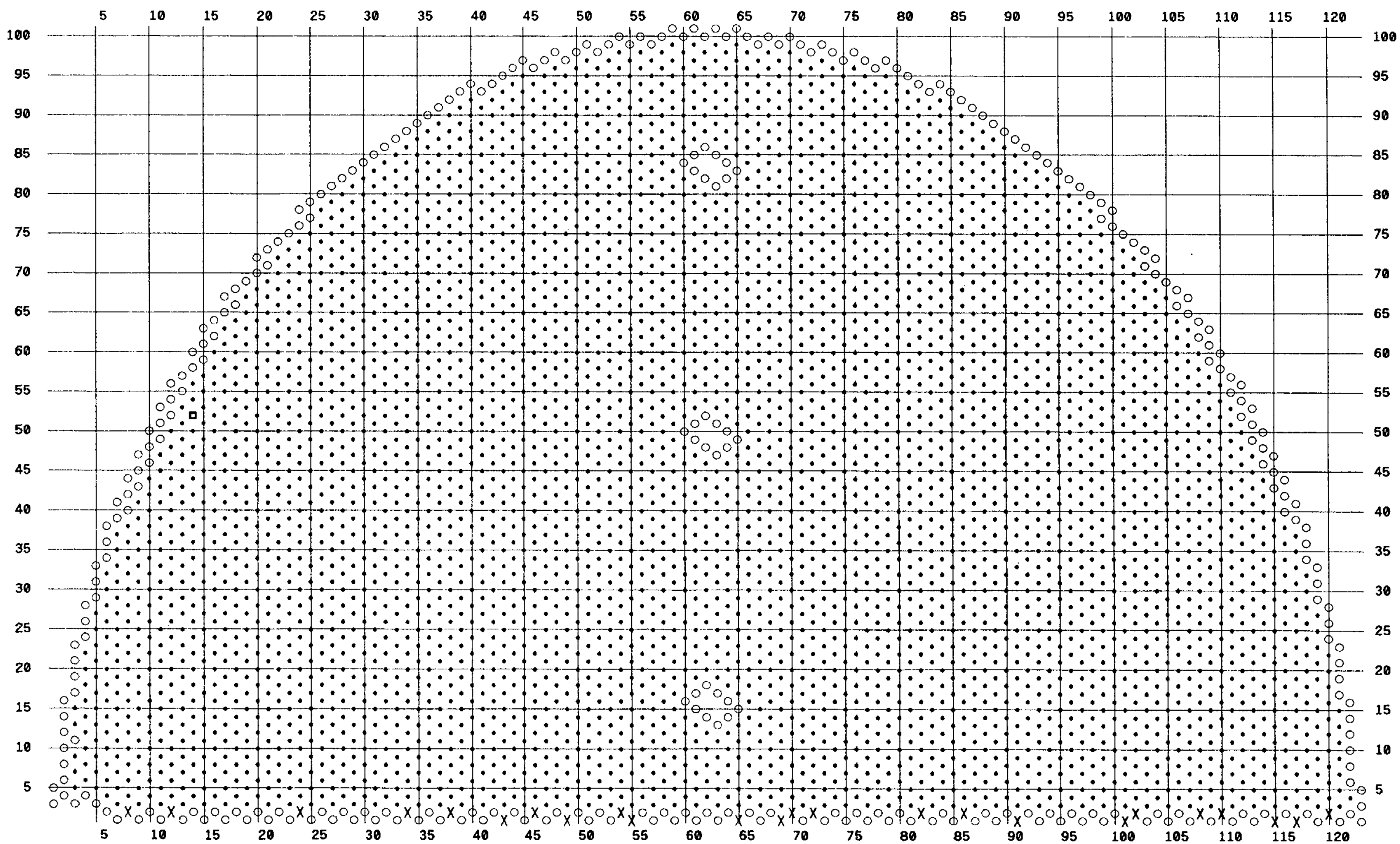
SG-A U-BEND PLUS POINT PROGRAM

Cold Leg Numbering View

R.E. Ginna RFO30 RGE RGEACL

X 24 TESTED U-BEND 08C - 08H

◘ 1 PLUGGED TUBE

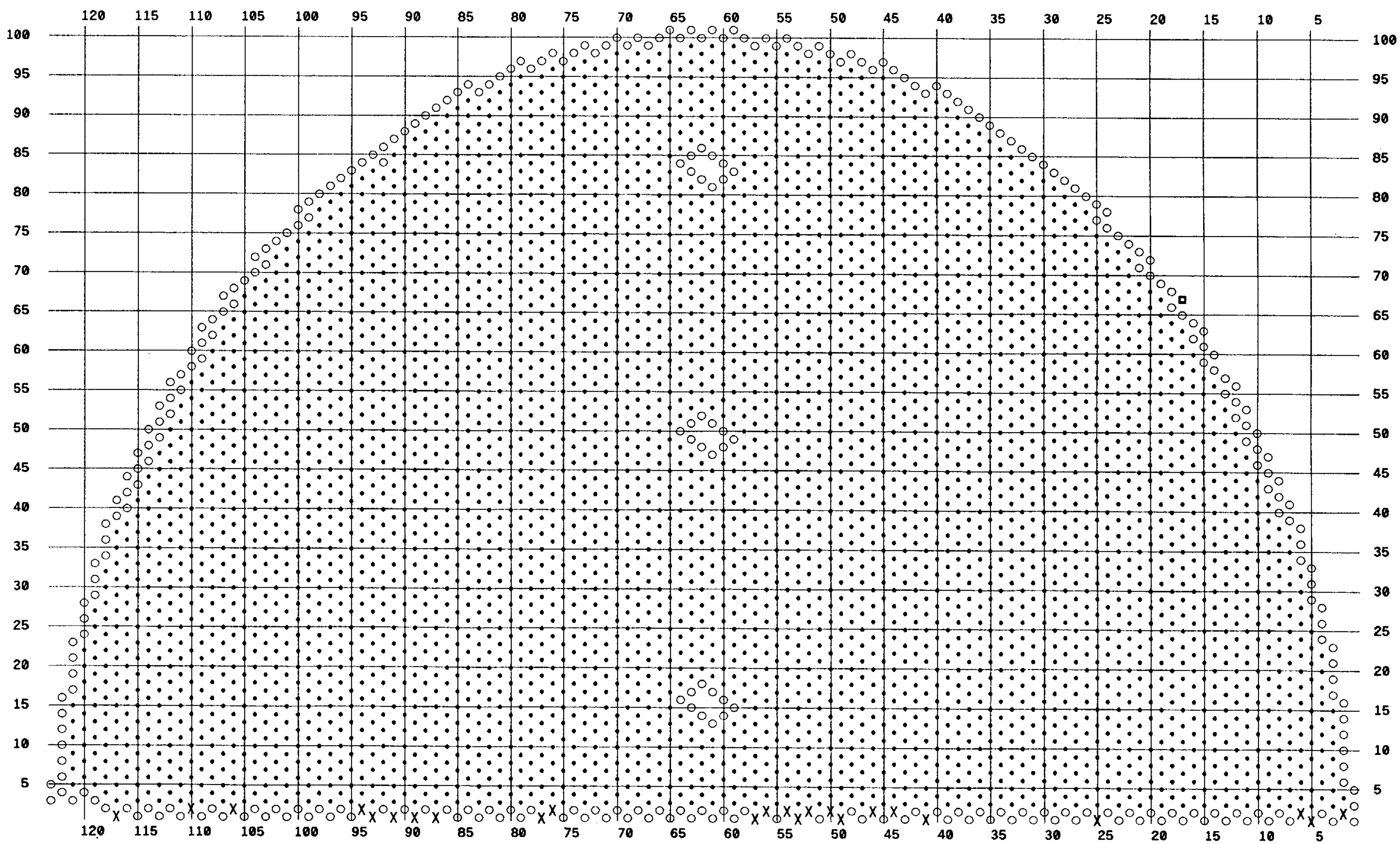


SG - B U-BEND INSPECTION PROGRAM

Hot Leg Numbering View
R.E. Ginna RFO30 RGE RGEBCL

X 24 TESTED U-BEND 08C - 08H

◻ 1 PLUGGED TUBE



Westinghouse Electric Company LLC - NSBU ST2000 03/28/2002 16:32:25

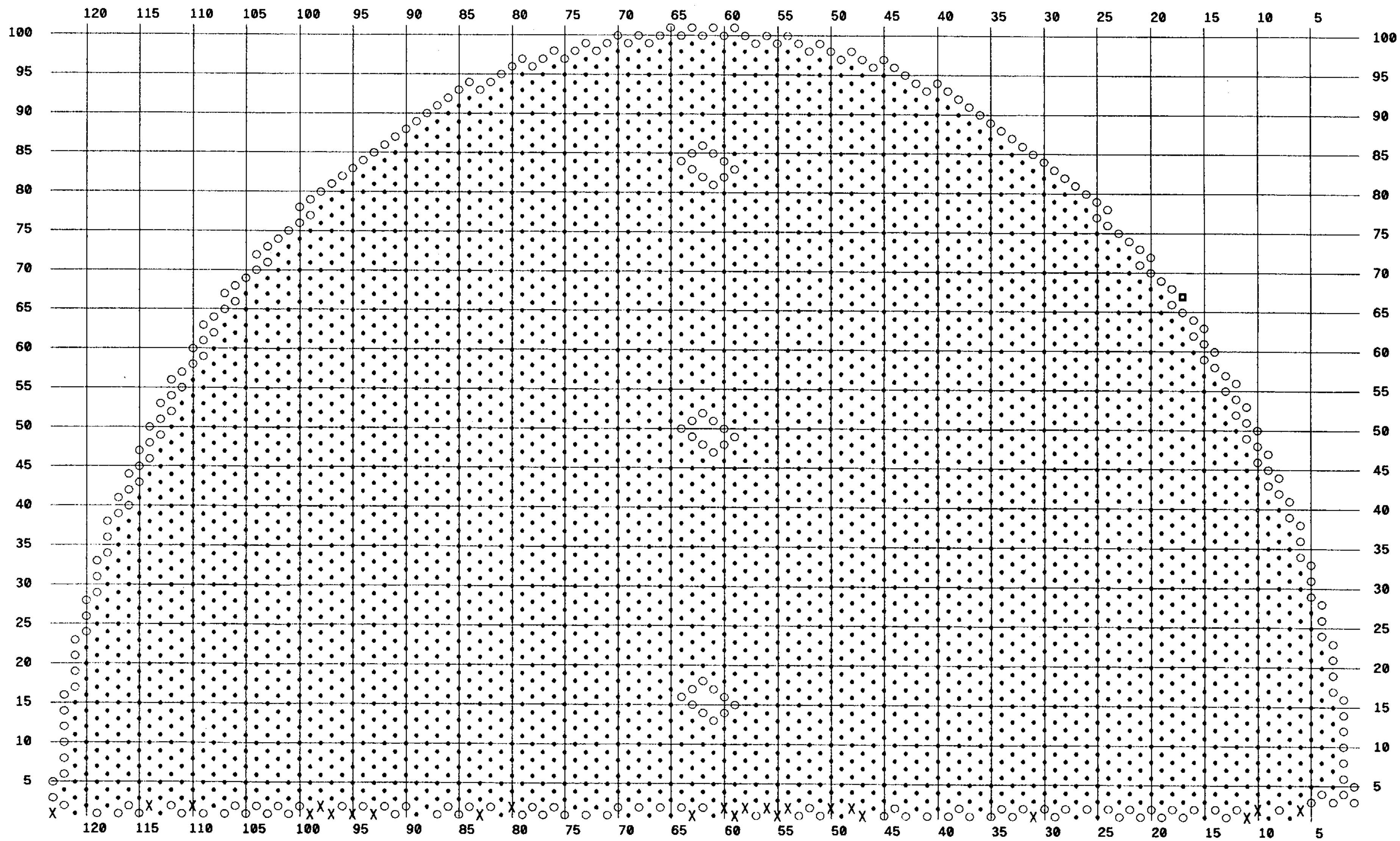
SG-B U-BEND PLUS POINT PROGRAM

Cold Leg Numbering View

R.E. Ginna RFO30 RGE RGEBCL

X 24 TESTED U-BEND 08C - 08H

□ 1 PLUGGED TUBE



Westinghouse Electric Company LLC - NSBU ST2000 03/28/2002 16:04:05

Attachment IV

R.E. Ginna Nuclear Power Plant

Steam Generator Tube Support Numbering Figure

Ginna BWI Replacement S/G

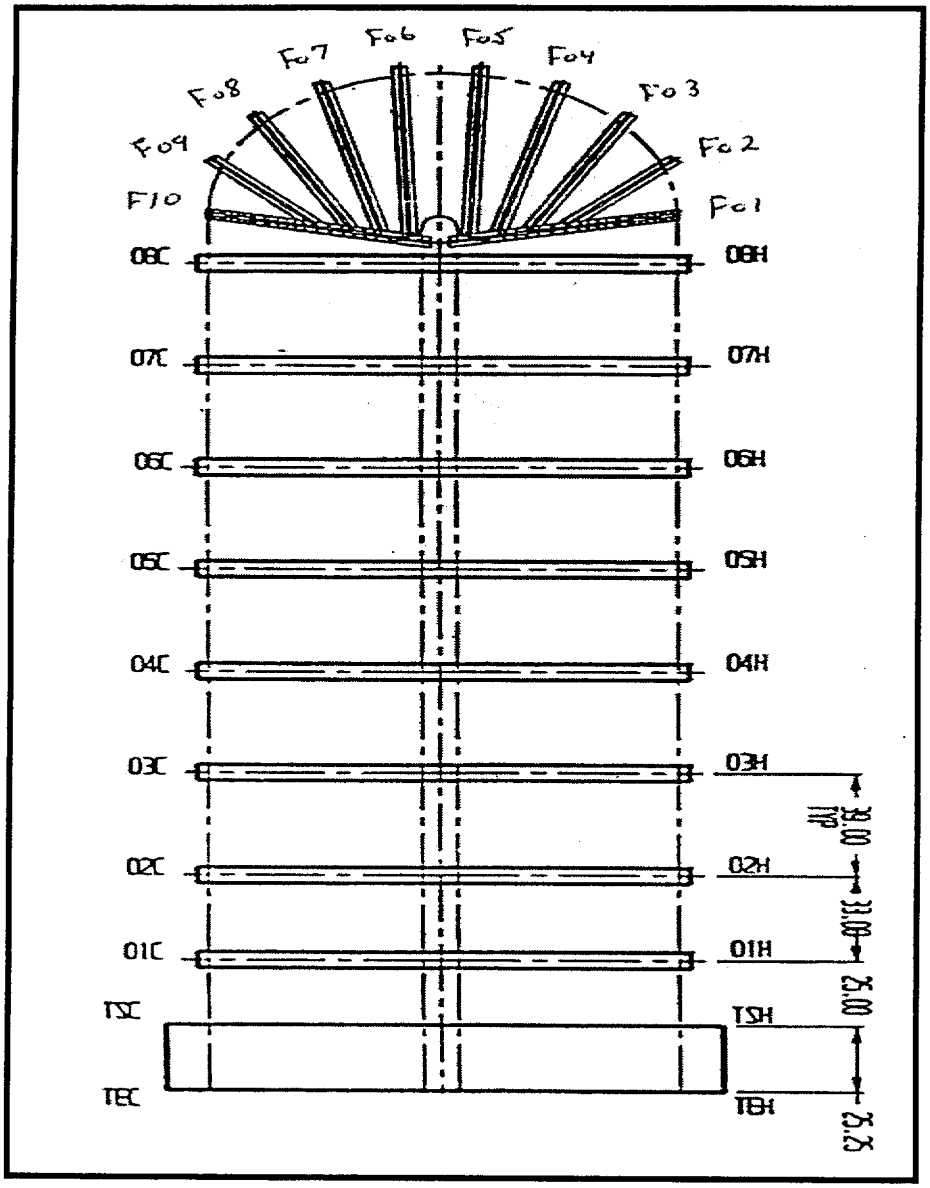


Figure 5-1