Non-Proprietary Version

Experience of U.S. and International Steam Generators with Alloy 600TT and Alloy 690TT Tubes and Sleeves

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Experience of U.S. and Foreign PWR Steam Generators with Alloy 600TT and Alloy 690TT Tubes and Sleeves

1. Introduction and Summary of Results

The purpose of this document is to summarize available information regarding the operating history of all U.S. and foreign PWR steam generators (SGs) with thermally treated Alloy 600 (A600 TT) and Alloy 690 (A690 TT) tubes and sleeves, particularly with regard to any occurrence of stress corrosion cracking (SCC). This information is to support the industry position that longer inspection intervals are reasonable for these steam generator materials than are currently allowed in Revision 5 of the EPRI PWR Steam Generator Examination Guidelines and in the various plant technical specifications.

In U.S. plants with A600 TT and A690 TT tubing, there has been a single possible instance of SCC. Indications of axial OD SCC were detected by bobbin coil and confirmed by Plus Point and Ultrasonic (UT) techniques in A600 TT tubing at Plant A during the recent May 2002 steam generator inspections. All of the indications were located at quatrefoil TSP intersections, and both hot leg and cold leg locations were affected over a range of elevations. This pattern is not typical of the IGA/SCC observed in plants with mill annealed Alloy 600 (A600 MA) tubing, so there is some uncertainty as to the cause of the indications. In response to these indications, Plant A has pulled two tubes for laboratory analysis. This examination will conclusively determine whether or not stress corrosion cracking is occurring, and may help identify its causes. However, since all of the indications were confirmed as cracking by UT, it is considered likely that some type of OD SCC is currently active at Plant A. The 9.6 EFPYs of operation at Plant A make it one of the youngest plants in the U.S. with A600 TT tubing, and the pulled tube examinations may provide some insight as to why cracking has been detected at Plant A earlier than at other similarly-designed U.S. SGs and why the cracking is not distributed in the normal pattern exhibited by IGA/SCC in A600 MA tubing. The Plant A cracking is possibly the first confirmed instance of SCC in A600 TT tubing in the U.S., despite the long operating experience of the tubing material (up to 15.5 EFPYs) and significant inspections conducted to date by the utilities. The plant ages and recent inspection scopes are shown in Table 1.

In 2002, a peer review was performed of all eddy current indications reported as potential cracking in A600 TT tubes in the U.S. prior to the spring 2002 steam generator inspections in order to determine if sufficient evidence exists to disposition each indication as either stress corrosion cracking or as some other benign condition (no indications of potential cracking have been reported in any A690 TT tubes in the U.S.). In all cases except two (i.e., 74 of 76 tubes), the peer review team unanimously agreed that the A600 TT indications were not representative of SCC, and in the other two cases the majority consensus (nine of ten peers) was that no SCC was present. The peer review is discussed in detail in Section 3.

There have been no instances of cracking of A600 TT or A690 TT sleeves in any U.S. plants.

In foreign plants with A600 TT tubing, there have been some instances of both PWSCC and OD IGA/SCC. However, none of this experience in known to directly apply to U.S. plants with A600 TT tubing because of differences in design and operating experience of the steam generators. For example, there has been significant PWSCC detected in French and South Korean plants with mechanical kiss roll tube expansions. However, kiss rolling produces significantly higher tube residual stresses than the hydraulic tube expansion method used in the U.S. Therefore, this experience indicates only that A600 TT tubing is susceptible to PWSCC in high stress environments, and does not indicate that significant SCC is imminent in U.S. plants with A600 TT. Similarly, the only confirmed instances of OD IGA/SCC in A600 TT tubing have been (1) circumferential cracks in dents at the top of tubesheet region and (2) shallow precursor IGA/SCC detected by metallurgical examination of blind pulled tubes (no detection of IGA/SCC by eddy current testing). Neither of these events suggest that cracking of U.S. SGs with A600 TT tubes is imminent. A recent EPRI visit to South Korea has learned that the Korean utility is reporting that PWSCC and OD SCC has been detected in A600 TT tubing at Plant B; however, the circumstances regarding the cracking are not known (i.e., if the cracking is as a result of some abnormal event or occurred during normal operation). The service experience of foreign plants with A600 TT tubing is discussed in detail in Section 5.

There have been no instances of cracking of A600 TT sleeves in any foreign plants.

There have been no instances of cracking of A690 TT tubes or sleeves in any foreign plants. The only known instance of corrosion of A690 TT is wastage of A690 TT hybrid expansion joint (HEJ) sleeves at Plant C4 that were laser welded after one cycle of operation. This wastage was detected by ECT and confirmed by examination of pulled tubes as occurring on the OD of some sleeves. The wastage was attributed to the presence of concentrated boric acid trapped in the space between the tube and the sleeve during the laser weld repair. Because of the unusual nature of the wastage, it is not directly applicable to the potential for cracking in U.S. SGs with A690 TT tubing during normal operation. The service experience of foreign plants with A690 TT tubing is discussed in detail in Section 5.

2. U.S. Plants of Interest

A list of all currently operating U.S. PWR steam generators with A600 TT or A690 TT tubing is shown in Table 1.[1,2,3,4,5,6,7] This table includes some design information for each plant such as the tube expansion method, type of tube support plates, and whether or not peening of the hot leg top of tubesheet (TTS) region was performed. It also includes the current plant hot leg temperature (T_{hot}), the age of each plant in terms of operating calendar years to April 1, 2002, the age in terms of the plant effective full power years (EFPYs) of operation as of the last ISI of the SGs (some ages were estimated where actual values are not available), and the inspection scope of the last SG ISI. The plant EFPYs and T_{hot} can be used to adjust the plant age to make comparisons of operating time on a consistent temperature basis.

A list of all U.S. PWR steam generators which installed Alloy 600TT or Alloy 690TT sleeves is shown in Table 2.[1] This table includes some design information such as the sleeve type, length, and top and bottom sleeve joint. The table also provides the number of sleeves installed, the maximum operating calendar years and EFPYs for each type of sleeve at each plant, and the current status of the affected steam generators (inservice, removed from service by replacing the steam generators, or removed from service by the plant being shut down).

3. U.S. Plant Service Experience with Regard to Cracking

The single probable instance of cracking in U.S. PWR steam generators with A600 TT tubing is shown in Table 3. Other eddy current indications which were initially reported as potential cracking in A600 TT tubes but which have subsequently been dispositioned as not being representative of stress corrosion cracking are shown in Table 4. The service experience of A600 TT and A690 TT in U.S. plants with regard to the occurrence of cracking is discussed in detail in the following paragraphs.

3.1 Possible OD IGA/SCC in A600 TT Tubing at Plant A

As shown in Table 3, indications of axial OD SCC were detected in A600 TT tubing at Plant A during the recent May 2002 steam generator inspections. A total of 42 axial indications were detected in 15 tubes, all of which were located in steam generator D (no defects were found in any of the other three SGs).[8,9] The indications were initially detected by bobbin coil, and were subsequently characterized by the use of Plus Point. All of the indications were at land areas of the quatrefoil tube support plates (TSPs). Indications were detected at both hot leg and cold leg locations, at elevations ranging from TSP 02H to 06H and TSP 03C to 05C. Subsequent testing with ultrasonic techniques (UT) confirmed the indications of axially-oriented OD SCC at both hot and cold leg TSPs.

In response to these indications, Plant A has pulled two tubes for laboratory analysis. Additional ultrasonic and eddy current testing of the pulled tubes will be performed in the lab prior to the destructive examination of the tubes. This examination will conclusively determine whether or not stress corrosion cracking is occurring at Plant A. However, since the 42 indications detected during the inspections were all confirmed as cracking by UT, it is considered likely that some type of OD SCC is currently active at Plant A.

This case is possibly the first confirmed occurrence of cracking of A600 TT tubing in the U.S. (other crack-like eddy current indications detected in U.S. plants have been dispositioned as not being representative of SCC, as is discussed in the next section). The 9.6 EFPYs of operation at Plant A make it one of the youngest plants in the U.S. with A600 TT tubing. The pulled tube examinations may provide some insight as to why indications of cracking have been detected at Plant A earlier than at other similarly-designed U.S. SGs, why all of the indications were located in a single steam generator, and why the indications are not distributed in a manner consistent with a thermally driven process (i.e., the IGA/SCC observed previously in A600 MA tubing).

While the eddy current results imply that some form of OD SCC has occurred in steam generator D at Plant A, it should be noted that the distribution of indications is not consistent with normal IGA/SCC experience, nor with the cracking being caused by a thermally driven corrosion process. This observation is based on the following:

- In A600 MA tubing, IGA/SCC has normally been first detected at lower hot leg TSP elevations where temperatures are highest. In subsequent years, IGA/SCC has then typically been detected in smaller numbers at higher (lower temperature) elevations in the hot leg, with the number of indications at the lower (higher temperature) elevations being much greater. Indications at cold leg elevations, which have significantly lower temperatures, have typically not been detected until long after large numbers of indications are seen on the hot leg. The indications detected at Plant A do not follow this pattern since, at first detection, they are located at low and high hot leg elevations and at mid-cold leg elevations.

- The typical distribution of IGA/SCC in steam generators with A600 MA tubing, with decreasing numbers of indications observed around the tube as one goes from the bottom of the hot leg up and around to the cold leg, has been attributed to two factors:

  — The primary side water temperature decreases about 4°F or 5°F for each TSP elevation as one goes up the hot leg. The decrease in primary water temperature decreases the temperature of the corrosion process, leading to lower corrosion rates as one goes up and around the U-bend.

  — The maximum available superheat at the TSP is set by the difference between the local primary water temperature and the secondary side saturation temperature. Thus, the maximum available superheat decreases as one goes up and around the U-bend. This tends to decrease the concentration of impurities in crevices, and thus tends to decrease the corrosion rates.

Considering the above inconsistency between normal IGA/SCC experience and the locations of the crack indications at Plant A, it is uncertain whether the Plant A indications are representative of normal thermally-driven IGA/SCC. Thus, the implications of the Plant A experience for other plants are somewhat uncertain.

3.2 <u>Other Alloy 600 TT Experience</u>

Prior to the steam generator inspections performed during the spring of 2002 (e.g., the Plant A inspections discussed above), indications reported as potential cracking by utilities have been reported at six U.S. plants with A600 TT tubing in their SGs. These indications are listed in Table 4. However, none of these indications have been confirmed as actual cracks by examination of pulled tubes or by supplemental tube examination using an alternative non-destructive examination (NDE) technique (e.g., ultrasonic testing). In 2002, EPRI conducted an expert peer review of all indications of potential cracking in U.S. A600 TT tubes prior to the Spring 2002 inspections, which are shown in Table 4. The peer review process and results are discussed in detail in the following paragraphs.[10,11,12]

The purpose of the peer review was to determine if sufficient evidence exists to disposition each indication as either stress corrosion cracking or a benign condition (i.e., non-cracking related indication such as deposits, manufacturing burnish marks, or other anomalous non-flaw indications) based on available knowledge from pulled tubes and ultrasonic or alternative examination techniques. In order to conduct the peer review, EPRI gathered information on all repaired A600 TT tubes at all U.S. plants. Based on the results of this survey, the following types of data were obtained for the peer review:

- Eddy current data for all indications reported as potential cracking for which neither supplemental pulled tube data nor ultrasonic testing data were available.
- Pulled tube data for both mill annealed Alloy 600 (A600 MA) and A600 TT indications. The purpose of obtaining the pulled tube data for A600 MA was as a reference to ensure that the disposition of the A600 TT indications would not compromise actual cracks.
- Eddy current data for A600 TT tubes that had been confirmed as not being indications of cracking by the use of ultrasonic testing.

Data were obtained from all U.S. plants that have reported crack like indications (a total of six plants) in A600 TT tubing. Data were also obtained from two other plants that had SGs with A600 MA tubes. Data from a total of 76 tubes that contained indications in A600 TT tubes were presented to the peer review team to be dispositioned for the presence of cracking. Ten of these tubes had previously been determined to not have cracking either by supplemental examination (UT or pulled tube) or, in one case, the indication disappeared after sludge lancing was performed. These 76 tubes include every crack like indication reported in any U.S. steam generator with A600 TT tubing prior to the Spring 2002 inspections.

Ten peers participated in the review of the A600 TT indications. Five of these peers were utility personnel, and five were from ECT vendors. All were qualified data analysts (QDAs) in good standing per the requirements of the EPRI PWR Steam Generator

Examination Guidelines. No formal training was given to the peers prior to analysis of the eddy current data; however, they were able to supplement their general knowledge of ECT by reviewing the indications from the ten A600 TT tubes where indications had already been shown not to be representative of cracking by a supplemental technique (ultrasonic testing or pulled tube examination) and the pulled tube data from the A600 MA tubing. In all cases except two (i.e., 74 of 76 tubes), the peers unanimously concluded that the A600 TT indications were not representative of stress corrosion cracking, and in the other two cases the majority consensus (nine of ten peers) was that no stress corrosion cracking was present. One peer disagreed with the consensus with regard to two indications from Plant E, which he felt were "crack-like until proven otherwise." Based on the results of this peer review, it is considered that prior to the Plant A experience discussed above, there were no confirmed cases of PWSCC or OD IGA/SCC in any U.S. plant with A600 TT tubes.

There have been no reported indications of cracking of A600 TT sleeves at any U.S. plant. As discussed above, the number, location, and years of service of all A600 TT sleeves in U.S. SGs is shown in Table 2.

3.3 Alloy 690TT Experience

There have been no instances of cracking of A690 TT tubes or sleeves at any U.S. plant. The only indications of any type of tube degradation of A690 TT tubes have been wear related, either due to loose parts or at a tube support structure.

4. Foreign Plants of Interest

A list of all currently operating foreign PWR steam generators with A600 TT or A690 TT tubing is shown in Table 5.[1,13,14,15,16,17,18,19,20,21,22,23,24] Table 5 includes some design information for each plant such as the tube expansion method, type of tube support plates, and whether or not peening of the hot leg top of tubesheet (TTS) region was performed. It also includes the current plant hot leg temperature (T_{hot}), the age of each plant in terms of operating calendar years to April 1, 2002, the age in terms of the plant effective full power years (EFPYs) as of the last ISI of the SGs (some ages were estimated where actual values were not available), and the inspection scope of the last SG ISI. The plant EFPYs and T_{hot} can be used to adjust the plant age to make comparisons of operating time with U.S. SGs.

A list of all foreign PWR steam generators which installed Alloy 600TT or Alloy 690TT sleeves is shown in Table 6.[1,15,16,18,24,25] This table includes some design information such as the sleeve type, length, and top and bottom joint type. The table also provides the number of sleeves installed, the maximum operating calendar years and EFPYs for each type of sleeve at each plant, and the current status of the sleeves (all of these sleeves have been removed from service by either plugging the sleeved tubes or by replacing the original steam generators).

5. Foreign Plant Service Experience with Regard to Cracking

All known instances of cracking in foreign PWR steam generators with A600 TT tubing are shown in Table 7. This table includes the type and location of the cracking, the tubing material in which the cracking was detected, the current level of cracking, and the date of the first detection of cracking and the age of the plant at that time in terms of operating years and EFPYs. The service experience of A600 TT and A690 TT with regard to the occurrence of cracking is discussed in detail in the following paragraphs.

5.1 PWSCC in French, South Korean, and South African Plants with A600 TT Tubing and Kiss Rolls

As shown in Table 7, extensive PWSCC has been detected in plants with A600 TT tubing and kiss roll tube expansions. A total of 26 French plants and two South Korean plants have experienced this type of cracking.[1,13,26,27,28] As a result of cracking the cracking detected early in plant life at some units, Electricité de France (EDF) decided to peen the inner diameter (ID) surfaces of the TTS areas of all of their units with A600 TT tubing. The two South Korean plants (Plant F1 and F2) also peened their TTS region. Recently, cracking has been detected for the first time at units that peened prior to operation (Plant G5, Plant H4, and Plant I1); all other PWSCC at kiss rolls reported in Table 7 has been at units which peened after the start of plant operation.

The rapid cracking observed in the kiss roll expansions prior to peening is attributed to the high residual tensile stress levels present on the ID surfaces of the tube expansion transitions. The maximum tensile hoop stress in a kiss roll expansion transition is reported by EDF to be 49 ksi, which is only slightly lower than the level of 54 ksi reported for normal roll expansion transitions.[29] By contrast, the residual tensile hoop stress in hydraulic expansion transitions is reported to be 28 ksi by EDF.[29] The rate of PWSCC has been found to vary approximately as the fourth power of the stress;[30]

therefore, the time to cracking in kiss roll expansions should be increased by a factor of $(49/28)^4 = 9.4$ to approximate time to cracking in hydraulic expansions such as are used in U.S. design plants with A600 TT tubing. The minimum time to detection of cracking in a normal undented kiss roll transition was 2.88 EFPYs at Plant H 1 (with many plants first detecting cracking after 3-5 EFPYs); this corresponds to a minimum time to detection of about 27 EFPYs for a hydraulic expansion plant at the Plant H 1 hot leg temperature of 616°F (denting related PWSCC is discussed below in Section 5.2). The oldest high temperature U.S. plant with A600 TT tubing is Plant E, with 13.9 EFPYs of operation at about 617°F (as of the last SG ISI). Since Plant E's age is approximately half of the time predicted to first detection of PWSCC based on the French experience, the rapid and extensive detection of PWSCC in plants with kiss roll expansions does not suggest that significant PWSCC is imminent in U.S. plants with A600 TT tubing.

There is one plant with A600 TT tubing, kiss roll expansions, and which peened after plant startup which is not included in Table 7. No PWSCC has been detected to date in the single steam generator with A600 TT tubes at Plant J 1, while extensive PWSCC has been detected in the two steam generators at Plant J 1 and three steam generators at Plant J 2 with A600 MA tubes (all of which have kiss roll expansions).[23]

5.2 PWSCC in French Plants with A600 TT Tubing and Dents at the TTS

Some of the PWSCC detected in French plants with A600 TT tubing and kiss roll expansions is attributed to denting occurring in sludge piles at the hot leg TTS region. This cracking was primarily circumferential (some axial cracking was observed in some units at the same time circumferential cracks were first detected), and was found in tubes in the low-velocity flow area near the center of the tube bundle where particles present in the secondary fluid tend to deposit and accumulate. Significant circumferential cracking was observed in four units (Plant K 1, Plant L2, and Plant M 3 and M 4) after as little as one cycle of operation. Iron-based metallic particles found in the tubesheet deposits of some SGs are believed to be the primary cause of the denting. The exact origin of the metallic particles is not known, but it is believed that they could have been introduced during plant construction either during SG finishing operations or during assembly of the components and piping of the feedwater plant.[31] Because of the presence of denting due to metallic deposits on the TTS, this experience is not directly applicable to U.S. SGs with A600 TT tubing (which have not observed similar denting to date), but it does show that the tubing is susceptible to rapid PWSCC in high stress regions.

5.3 PWSCC in Japanese Plants with A600 TT Tubing

As shown in Table 7, PWSCC has been detected by ECT and confirmed by destructive examination of pulled tubes in three Japanese plants with A600 TT tubing. These three plants (Plant N 1, Plant O 3, and Plant O 4) have both hydraulic expansions and full depth hard roll expansions. The location of the cracking has been in the hard roll expanded area, either at the end of the top hard roll where the tube transitions to the hydraulically expanded area or in areas of overlap between adjacent hard rolls.[32] The cracking has not occurred in the hydraulic expansion transition region. Examination of a tube pulled from Plant O 4 also showed that the tube hole in the tubesheet was ovalized on one side due to non-concentric polishing during fabrication, and that the tube cracking occurred in this area of ovalization. In general, the region where cracking has been observed in these three plants is thought to have residual stress levels between those of hard roll expansion transitions and hydraulic expansion transitions, although actual levels are not available. Stress levels will be higher if the tube hole is ovalized as was observed in the tube pulled from Plant O 4. Therefore, the Japanese experience is not directly applicable to U.S. SGs with A600 TT tubing (which have hydraulic expansions only), but it shows that A600 TT tubing is susceptible to PWSCC in moderately high stress regions after long periods of operation.

5.4 OD IGA/SCC in Japanese Plants with A600 TT Tubing

Tubes pulled from Plant O 3 in 1996 and Plant P 2 in 1997 with no NDE signals showed evidence of precursor IGA/SCC.[33,34] Shallow intergranular corrosion was observed in the hot leg TTS region under hard sludge with a maximum depth of 50 μm (4% of wall) at Plant O 3 and 10 μm (0.8% of wall) at Plant P 2. The tubes were pulled after 11 and 10 years of operation, respectively. These results indicate the potential long-term susceptibility of A600 TT tubing to OD IGA/SCC.

5.5 PWSCC and OD SCC in A600 TT Tubing at Plant B 2

Tubes pulled from Plant B 2 in 1988 confirmed the presence of OD cracking in the dented region just above the TTS and shallow circumferential PWSCC in the expansion transition just below the TTS.[35] The denting is believed to have been caused by a combination of sea water ingress through the condenser early in plant life combined with the presence of foreign iron material on the top of the tubesheet in the sludge pile region. This denting resulted in cracking of A600 TT tubes in just three cycles of operation (2.43

EFPYs). Because of the presence of denting due to metallic deposits on the TTS, this experience is not directly applicable to U.S. SGs with A600 TT tubing (which have not observed similar denting to date), but it does show that the tubing is susceptible to OD IGA/SCC and PWSCC in high stress environments.

5.6 Potential PWSCC and OD SCC in A600 TT Tubing at Plant B 3

During a recent EPRI visit to South Korea, it was learned that the Korean utility is now reporting that PWSCC and OD SCC have been detected in the TTS region in thermally treated tubes at Plant B 3.[36] No further information is currently available about the cracking, and it is not known if the cracking is as a result of normal operation or due to some abnormal event (such as denting in the TTS region like was observed at Plant B 2).

5.7 ECT Signals of OD IGA/SCC at the TTS in French Units with A600 TT Tubing

Eddy current indications have been detected in the hot leg TTS region at Plant Q 4, Plant R B3 and B4, Plant S 4, Plant T5 and 6, and Plant M 1, M2, and M3.[13] These are small indications which are close to the eddy current threshold for calling these types of signals. Two tubes were pulled from Plant T5 in 1995 and one tube was pulled later (unknown year) to investigate the signals.[1] In none of the three cases did the destructive examinations confirm the presence of IGA/SCC. EDF considers that the signals may be related to deposits on the tubing. Since there has been no evolution of the ECT signals, and since the pulled tube examination from Plant T5 did not confirm the presence of degradation, EDF considers that the signals are not indicative of degradation.[20]

5.8 Alloy 690 TT Experience

There have been no instances of cracking of A690 TT tubes or sleeves. The only known instance of in-service corrosion of A690 TT is wastage of sleeves at Plant U 4. The sleeves were hybrid expansion joint (HEJ) mechanical sleeves that were installed in 1993 and caused parent tube cracking in less than a cycle. In order to keep the sleeves in-service, the sleeves were expanded above the existing upper joint and laser welded to the tubes in 1994. In 1995, wastage on the OD of some sleeves was detected by ECT and confirmed by the examination of pulled tubes. The wastage was attributed to the presence of concentrated boric acid trapped in the space between the tube and the sleeve during the laser weld repair.[16] Because of the unusual nature of the wastage, it is not directly applicable to U.S. SGs with A690 TT tubing (since they do not have similar primary side crevices where boric acid concentration could occur). No other wastage related degradation of A690 TT has been observed at any plant.

6. Foreign Plant Extended Inspection Interval Experience

The following are some examples of extended operating intervals currently being utilized for foreign steam generators with A600 TT or A690 TT tubing:

- Plant V 1 and 2: 100% of the A690 TT tubes at Plant V are currently inspected by bobbin coil once every five years. An additional 10% inspection of the hot leg and cold leg TTS region is inspected by rotating probe once every five years. Thus, Plant V 1 was last inspected in 1997 and will not be inspected again until 2002, and Plant V 2 was last inspected in 2000 and will not be inspected again until 2005.[18]

- Belgian Replacement SGs: The Belgian utility is inspecting the replacement SGs at Plant U 4 and Plant W 1 and 3 (all of which have A690 TT tubing) each outage. However, they are currently inspecting only the minimum number of required tubes (3% of the total population by bobbin coil). No rotating coil inspections are being performed.[16] However, all of the replacement SGs are recent (1996 or later), and it is not known if there are future plans to increase the inspection extent.

- Plant X 2 and 3: A total of 50% of the A690 TT tubes at Plant X 2 and 3 are currently inspected by bobbin coil every other year. An additional small sample inspection of the hot leg top of tubesheet region is inspected during these outages.[15] Thus, 100% of the tubes are inspected over a four-outage interval, but inspections are not performed during each outage.

- France: In France, steam generators with A600 TT tubing are inspected every other cycle by bobbin coil in order that 100% of the tubes are inspected once every eight cycles. Additional inspections are performed each outage for areas of interest, such as peripheral tubes (to look for loose parts damage) or in the sludge pile region using bobbin coil and/or rotating probes. In units with A690 TT tubing, bobbin coil inspections are performed less often (1/8 of tubes in 1 SG per cycle in 900 MW units and 1/8 of tubes in 2 SGs per cycle in 1300 and 1400 MW units), such that 100% of tubes are inspected once every 16 cycles. Additional inspections are performed every other outage for areas of interest, such as peripheral tubes (to look for loose parts damage). No rotating coil inspections are performed of A690 TT tubes except at Plant Y 1, which is the leading plant (i.e., longest operating time) with A690 TT tubing in the French fleet.[20]

7. Experience of Units with Both A600 TT and A600 MA Tubing

There are four units worldwide where both A600 TT and A600 MA tubing are present in the same unit. These four units provide a direct comparison of the performance of A600 TT tubing relative to A600 MA tubing in identical environments. The experience of the four units with regard to the occurrence of PWSCC and OD SCC in the TT and MA tubes is shown in Table 8 and is as follows:

- Plant Q 4: Plant Q 4 has two steam generators with A600 MA tubing and one steam generator with A600 TT tubing. As shown in Table 8, it has experienced significant PWSCC of the MA tubes, with 52% of the tubes reported as cracked at the last SG ISI. The TT tubing has performed better, with 3% of the tubes reported as cracked at the same time. All of the tubes have kiss roll expansions and were peened after the start of plant operation, with the MA tubes peened after three cycles and the TT tubes peened after nine cycles. No OD SCC has been reported at Plant Q 4 in either the MA or TT tubing. The Plant Q 4 experience shows a estimated minimum factor of improvement of 2.0 with regard to the first detection of PWSCC in A600 TT tubing relative to A600 MA tubing (the factor of improvement can be estimated since cracking was first detected in each type of tubing at the first cycle after peening).

- Plant J 1: Plant J 1 has two steam generators with A600 MA tubing and one steam generator with A600 TT tubing, and its SGs are of similar design to Plant Q 4 (e.g., kiss roll tube expansions). As with Plant Q 4, Plant J 1 has experienced significant PWSCC of the MA tubes, with 35% of the tubes reported as cracked at the last SG ISI. However, none of the TT tubes are reported as being cracked, probably as a result of the shot peening performed after two cycles of operation. OD SCC has been detected in a small number of tubes (seven tubes affected to date), beginning after about 10 EFPYs of operation. No quantitative assessment of the factor of improvement with regard to the first detection of PWSCC in A600 TT tubing relative to A600 MA tubing can be made because of the shot peening performed early in plant life; the experience with OD SCC shows a minimum factor of improvement of about 1.3 with regard to time to first detection in A600 TT tubing relative to A600 MA tubing.

- Plant E: At Plant E, the lowest ten rows in each steam generator are A600 TT, while the remaining tubing (rows 11 and higher) are all A600 MA. Both OD SCC and PWSCC have been detected in the A600 MA tubes, with 231 tubes (1% of the total) plugged for PWSCC and 114 tubes (0.5% of the total) plugged for OD SCC. All of the corrosion has been detected in the hydraulically-expanded TTS region. In contrast, no SCC has been confirmed to date in the A600 TT tubing. The Plant E experience shows a minimum factor of improvement of 1.6 with regard to the first detection of SCC in A600 TT tubing relative to A600 MA tubing.

- Plant Z 2: At Plant Z 2, there are a total of 15 A600 TT tubes installed in the steam generators, while all of the remaining tubing is A600 MA. OD SCC has been widespread in the A600 MA tubing, with approximately 20% of tubes affected and almost 1000 tubes plugged for this type of degradation (not including the tubes preventively plugged in 2001 to reduce the primary-to-secondary leak rate). Circumferential PWSCC has recently been detected in the hydraulically expanded region at the top of the tubesheet, despite the fact that this region was shot peened after one cycle of operation. In contrast, no cracking has been detected in any of the A600 TT tubes. The Plant Z 2 experience shows a minimum factor of improvement of 2.3 with regard to the first detection of OD SCC in A600 TT tubing relative to A600 MA tubing; no assessment of the factor of improvement with regard to PWSCC can be made because of the shot peening performed early in plant life.

8. Unavailable Data

Steam generator degradation data were obtained for all foreign utilities which are currently members of EPRI, and also for the South Africa utility. Data from utilities in the following countries were not available:

- South Korea: The South Korean utility was an EPRI member through about 1998, so data which were already available in the EPRI SGDD or in DEI's Steam Generator Database as of that time are listed in this report. A recent EPRI visit to South Korea has learned that the Korean utility is now reporting that PWSCC and OD SCC has been detected in the TTS region of A600 TT tubes at Plant B 3. However, no details are available, so the significance of the cracking is unknown.

- Taiwan: The Taiwanese utility is not a member of EPRI, so no data were available in the EPRI SGDD. DEI has no experience reports in our Steam Generator Database for the Maanshan units. Obtaining information will likely be of value, since Maanshan has some of the oldest Model F steam generators in service in the world (commercial operation in 1984 and 1985). A contact was obtained by DEI at Maanshan and a request for information was sent, but no answer has been received.

- China: The Chinese utility is not a member of EPRI, so no data were available in the EPRI SGDD. DEI has no information on the operation of the Daya Bay plant. An initial contact with the Framatome Owner's Group (FROG) indicated that no corrosion has been detected at either unit, but no additional information was given.[22] The FROG asked that EPRI formally request an information exchange in order to consider whether to provide the data. The current status of this information exchange request is not known.

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Table 1

Table 2

Table 3

Table 4

Table 5

Table 6

Table 7

Table 8