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U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

South Texas Project
Unit 2
Docket No. STN 50-499
Special Report on Steam Generator Tube Inspection Results

In accordance with Technical Specifications 4.4.5.5a, 4.4.5.5c, and 6.9.2, STP Nuclear Operating Company submits the attached Special Report on steam generator tube inspection results. This Special Report provides the required information for the C-3 report to be submitted prior to resumption of plant operation as well as the required information for the 15-day post-inspection report.

If there are any questions regarding this report, please contact Mr. Mark Kanavos, Steam Generator Replacement Project Engineer, at (361) 972-7181 or myself at (361) 972-7902.

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Special Report on Steam Generator Tube Inspection Results

South Texas conducted eddy current testing on all four steam generators during the eighth refueling outage of Unit 2 (2RE08). On March 19, 2001, with the reactor in mode 6, South Texas Project (STP) Unit 2 Steam Generator 2C eddy current inspection results for the end-of-cycle 8 (2RE08) inspection fell into Category C-3. A total of 48 defective tubes out of a sample population of 4615 (100%) in Steam Generator 2C were identified. Inspection results for the other three Unit 2 steam generators were classified C-2, as shown in Table 1 near the end of this report.

Summary of Eddy Current Examinations Performed

The basic eddy current examination scope for this outage was inspection of all in-service tubes in all four steam generators by the bobbin coil probe full length (except for the U-bend portion of tubes in rows 1 and 2, where a 100% inspection of row 1 and a 20% sample of row 2 was performed using the Plus Point probe). At tube-to-tube support plate intersections where the three volt alternate repair criteria applies (plates C, F, and J), all indications with bobbin voltage exceeding the repair limit plus a sizable sample of intersections with bobbin voltage less than the repair limit (well in excess of the 100 required by the Technical Specifications) were examined by Plus Point. At all other tube-to-tube support plate intersections, all indications with bobbin voltage exceeding 1.0 volts were examined by Plus Point. Outside of tube-to-tube support plate intersections, all bobbin indications that were non-quantifiable and could not be traced back to the baseline inspection data were also examined using the Plus Point probe. Additional sample inspections of various special interest areas (e.g., the hot leg expansion transitions, paired dings, dings over 5.0 volts, preheater baffle expansions) were performed using the Plus Point probe.

Background Information Regarding the Unit 2 Model E Steam Generators

- Age of the Unit 2 steam generators at 2RE08 was 8.89 effective full-power years.
- Length of the preceding cycle (Cycle 8) was 458 effective full-power days.
- The tube-to-tubesheet design is hydraulic expansion.
- Previous outage (2RE07) inspection results: 187 tubes plugged (total - see Reference 1).
- Tube support plate design is drilled-hole stainless steel.
- Tube material is Alloy 600 mill annealed (except for 15 Alloy 600 thermally treated tubes in SG 2D).
- Shot peening of the expansion transition at the top of tubesheet was performed in the hot leg after the first cycle, and in the cold leg after the second cycle.
- U-bend heat treatment was performed on Row 1 and Row 2 tubes prior to initial operation.
- Model E Row 1 U-bends have a larger bend radius (3.25") than most other Westinghouse steam generator designs (e.g., 2.19" for Model 51 & Model 44 SGs; 2.25" for Model D SGs).

Examination Results

The inspection results are discussed below by degradation mechanism. A summary of how many defective tubes were attributed to each of these damage mechanisms is provided in Table 1. As discussed below, many tubes were also preventively plugged. A summary of all tube plugging is given in Table 2. Figure 1 provides identification of the tube support plates in the Model E steam generators.

1. Primary Damage Mechanism - ODSCC at Hot Leg Tube-to-Tube Support Plate Intersections

   By far the most prevalent degradation mechanism detected in 2RE08 was axially-oriented outer diameter stress corrosion cracking (ODSCC) at the hot leg tube-to-tube support plate intersections. Eddy current data for these indications is consistent with data from tubes pulled in 1998 (2RE06), where destructive examination has proven such cracking to be the result of ODSCC in the tube support plate crevice region (see References 2 and 3). These indications are similarly consistent with the destructive examination results of tubes pulled at other plants (including South Texas Unit 1) to understand similar eddy current indications.

   During the 2RE08 steam generator inspection, the 3 volt alternate repair criteria (ARC) was implemented in accordance with License Amendment 114 (Reference 4). (The 3 volt ARC was pursued by STP as a corrective action from the previous C-3 event during the 2RE07 steam generator inspection.) Some large voltage indications were found at the lower support plates in all SGs; however, all of these were located at plates that do not deflect significantly under accident conditions as shown by the bounding analysis without tube locking performed to support the 3 volt ARC. The largest indication in each steam generator was as follows: 8.05 Volts in tube R23C24 at the C (02H) plate in SG 2A, 9.72 volts in tube R15C89 at the C (02H) plate in SG 2B, 8.96 volts in tube R22C92 at the J (04H) plate in SG 2C, and 11.09 volts in tube R24C47 at the F (03H) plate in SG 2D. At the plates where the 1 Volt ARC continues to apply (i.e., at the flow distribution baffle and all tube support plates other than C, F, and J), only one indication exceeded the upper voltage repair limit (R20C29 in SG 2B; 5.27 volts at the 05H tube support plate) and none exceeded the structural limit (5.69 volts). There were no indications at flow distribution baffle plate intersections. At tube-to-tube support plate intersections, there were no indications of primary water stress corrosion cracking (PWSCC); there were no indications of predominantly circumferential cracks; and there were no axial indications extending outside the plate. The growth rate of indications at support plate intersections was increased over that experienced during previous cycles, but was comparable to growth rates experienced by the Byron and Braidwood plants during the period in which they operated under a 3 Volt ARC with locked support plates.

   Possibly Leaking Tubes

   STP Unit 2 experienced operational primary-to-secondary leakage for the first time during Cycle 8. Accordingly, a secondary side tube leak test was conducted in accordance with the recommendations of the EPRI Tube Integrity Guideline, Section 10, "Operational Leakage"

to identify possibly leaking tubes. The test began early in the outage, shortly after the primary manways were opened. Secondary side water level was established well above the tube bundle, and nitrogen pressure was applied to the secondary side of all steam generators. The test pressure was raised in increments of about 200 psi until the maximum test pressure was established at about 600 psig on the secondary side, with the primary side at atmospheric pressure. Pressure was maintained at about 600 psig for about four days. It was necessary to secure primary side ventilation of the steam generators to identify most of the leaking tubes, as the leak rate was in nearly all cases slower than the evaporation rate that resulted from the ventilation. The secondary pressure test was completed at about midnight on the night of March 15th. None of the tubes that evidenced leakage were dripping faster than 1 drip per minute. Most did not drip at all; the primary tube face was observed only to be damp, and in some cases may have been wet by leakage from a nearby tube. The largest number of tubes with evidence of possible leakage was in SG 2A. This is consistent with the prior cycle operational leakage experience (see section II.C below), as SG 2A had the largest operational leak rate. There was good correlation with tubes with high voltage indications at tube-to-tube support plate intersections. All tubes determined to possibly be leaking were plugged.

Leaking Tube-to-Tube Support Plate Intersections - Industry Experience

There are no other domestic plants that have experienced measurable operational leakage at tube-to-tube support plate intersections (including STP Unit 1 Model E steam generators); however, STP Unit 2 is the only domestic plant to use stainless steel drilled hole support plates. The Belgian plants with Model E steam generators with drilled hole stainless steel support plates (Doel 4 and Tihange 3) operated under a voltage-based repair criteria for tube-to-tube support plate intersections for multiple cycles prior to replacement. During outages in 1990 and 1992, low pressure secondary side leak tests by fluoresceine performed at Doel 4 were successful in identifying leakage in a number of tubes that was attributed to ODSCC at tube-to-tube support plate intersections.

Ultrasonic Testing and In Situ Pressure Testing of Indications at Tube-to-Tube Support Plate Intersections

The four largest (by bobbin voltage) indications at tube-to-tube support plate intersections in SG 2D were examined by ultrasonic testing (UT). The UT examinations confirmed that the dominant degradation mode was axial, with about 7-8 dominant cracks detected at each tested intersection with from three to seven through-wall. In one intersection, one short crack was noted to have an oblique orientation that was about 60° off the vertical, (no circumferential extent was apparent in the eddy current data). All cracks observed at the four UT tested intersections were confined well within the support plate.

These same four intersections in SG 2D were subsequently in situ tested for burst (proof) and leak in accordance with EPRI Guidelines. The two largest indications at tube-to-tube support plate intersections in SG 2B were also in situ tested for leak and burst. Each of the tubes containing the tube-to-tube support plate intersections selected for in situ testing had shown

evidence of leakage during the secondary side tube leak test, and two of the tubes exhibited leakage even before the ventilation was secured (i.e., they were likely the two with the largest operational leak rate). The in situ pressure proof tests were conducted to demonstrate that the axial tearing limit was not exceeded. Leak testing was also performed in accordance with the industry Lessons Learned from Recent Plant Experience, which was conservatively interpreted to recommend that leak testing be performed for any proof tested tubes. Proof testing was performed with a bladder. All four of these indications exhibited some leakage during the in situ leak test, ranging from 0.07 gpm to 1.2 gpm at steam line break differential pressure. Proof testing with end cap loading was successfully performed, demonstrating structural integrity relative to axial tearing.

<u>Additional Measures Taken</u>

To lessen the likelihood of significant operational leakage during Cycle 9 and to limit the number of large voltage DSIs at the end of Cycle 9, STP undertook a preventive plugging plan for indications at support plate intersections that did not exceed the repair limit at the three volt plates (C, F, and J; 02H, 03H, 04H). This plan was implemented as follows:

- All indications >1.5 volts at tube-to-tube support plate intersections were plugged (about 105 tubes).
- Plus Point inspection of all indications between 1.0 and 1.5 volts was performed. (~370)
- Plus Point inspection of selected indications between 0.6 volts and 1.0 volts was performed (~800).
- Sizing analysis on this population was performed.
- Results were evaluated and the tubes most likely to exhibit high growth were preventively plugged.

2. Other Damage Mechanisms Seen Previously in the Unit 2 Steam Generators

<u>Axially-Oriented Stress Corrosion Cracking in the Freespan Regions at "Ding" Locations</u>

A damage mechanism previously observed in the STP Unit 2 steam generators observed again in 2RE08 was axially-oriented ODSCC in the freespan regions at "ding" locations. There were 22 such indications identified in 2RE08, compared to 9 in 2RE07. As used here, a "ding" means minor damage to the tube in the free span region. Most dings were introduced during the manufacturing processes and are apparent in baseline data. This damage mechanism does not appear to be temperature driven, as 16 of the 22 were detected in the cold leg. Five of the tubes in this category were detected by a bobbin non-quantifiable indication (NQI) call (subsequently confirmed by Plus Point), in which there is no direct eddy current evidence of a ding. The existence of some form of manufacturing-induced damage

too small to see by eddy current, or completely involved in the degradation, is inferred in these cases. All but two of the indications were determined to be OD-initiated from the eddy current data, although post-inspection review indicates that two of these flaw signals are too small to accurately assess, and are possibly ID-initiated. This damage mechanism is not new to the industry. Prior to 2RE07, STP undertook a successful qualification program to demonstrate that with the proper setup and analyst training, the bobbin probe could be qualified to detect axial OD indications at dings of 5 volts and under (subject to confirmation by rotating probe). All dings above 5 volts were inspected by Plus Point. Since the final inspection included 100% of the full length of all tubes (either by bobbin or Plus Point, except for ~80% of the Row 2 U-bends in three SGs), a highly comprehensive inspection was performed during 2RE08. The STP experience with the defects caused by this damage mechanism is that they are slow growing; flaws are detected and removed from service before they grow to a size that challenges tube integrity. During 2RE08, two of these indications met the screening criteria for in situ testing (one additional axial indication was tested together with the circumferential indication at a paired ding as discussed below). These indications were successfully tested for leak (no evidence of leakage) and burst.

Volumetric Indications in the Freespan

Four such indications were detected during 2RE08, all in the freespan region on the hot leg side. These indications were detected as non-quantifiable indications (NQI) by bobbin, and were confirmed as single volumetric indications (SVIs) by three-coil probe with Plus Point. These indications are most likely small patches of intergranular attack (IGA), and may also be associated with areas damaged during the manufacturing processes, although no indications of a ding are present in the eddy current data at these locations. These flaws were evaluated against the in situ screening criteria developed in accordance with EPRI Guidelines and none required testing. (Note: See discussion at the end of Section 5 below for explanation of why Table 1 identifies five tubes with this damage mechanism.)

3. Other Damage Mechanisms Seen Previously in the Unit 1 Model E Steam Generators, New to Unit 2

Circumferential Cracking at the Hot Leg Top of Tubesheet

Based on the occurrence of this damage mechanism at Callaway (the only other domestic plant with hydraulically expanded Alloy 600 ma tubing) the potential for this mechanism to occur at STP Unit 2 has been recognized for some time. Although the hydraulic tubesheet expansion employed in the STP Unit 2 steam generators results in a more favorable stress condition at the expansion transition than does the alternative of hard roll expansion, degradation was expected eventually to be detected at STP Unit 2. Predictions of circumferentially oriented flaws at or near the hot leg expansion transition region prompted the development of stabilization criteria and defect specific in situ screening criteria for this damage mechanism prior to 2RE07. A critical area was defined in the Degradation Assessment prior to the 2RE07 outage (and was utilized again in 2RE08) based on prior

Model E experience with this damage mechanism. In 2RE08, as in 2RE07, the first sample included 100% of the critical area and 20% of the remainder of the tubes by Plus Point. Flaws were detected outside of the critical area in the first sample during 2RE08, so the sample was expanded to 100% of in-service tubes in all four steam generators. In all, nine circumferential indications were detected at the top-of-tubesheet.

ODSCC and PWSCC at the expansion transition has been detected in the Callaway mill annealed tubing for several cycles; however, all but one of the top-of-tubesheet circumferential indications detected in STP Unit 2 during 2RE08 were determined to be OD-initiated based on the eddy current data. One of the hot leg circumferential indications was characterized as most likely ID-initiated. STP performed shot peening very early in plant life (first refueling outage for hot leg, second for cold leg), providing protection from early ID degradation, whereas Callaway did not perform peening until much later in their plant life (in the fifth refueling outage). In accordance with industry lessons learned from recent Industry Experience, this new damage mechanism was screened for any unusual characteristics that would have triggered burst testing irrespective of the screening criteria. No such unusual characteristics were seen when the STP circumferential cracks were reviewed by both the STP Independent Level III eddy current analyst and by the Callaway Independent Level III eddy current analyst (who was on site at STP as a resolution analysis for the STP 2RE08 outage). Nevertheless, two of these indications were selected for in situ as a new damage mechanism (neither met the screening criteria developed per EPRI Guidelines). Both were tested for leakage and burst in accordance with EPRI Guidelines and successfully passed. No leakage was detected during the leak test (burst testing was performed with a bladder).

Circumferential Cracking at "Paired Dings"

This degradation mechanism was first detected in STP Unit 1 at the last inspection prior to replacement (1RE08). In that inspection, circumferentially oriented indications were reported at cold leg "paired" dings between tube support plates 11C and 12C. Paired dings are dings spaced by the thickness of the top tube support plate, and are believed to have been caused by application of a bending moment to the tube during tube insertion, resulting in two circumferentially oriented dings with the indicated spacing. This damage was addressed in the STP Unit 2 Degradation Assessment for both 2RE07 and the current inspection. It has not to our knowledge been detected in any other plants. During 2RE07, a large sample of paired dings was inspected by Plus Point (including 100% in SG 2D) and no circumferential degradation was found. No cracking at dings in the Belgian Model E steam generators was encountered prior to their replacement based on STP correspondence with Laborelec in September 1997.

The flaw identified during the 2RE08 inspection occurred in SG 2D in tube R6C10 at a location 3.5" above preheater baffle plate 16C. The indication in 2D confirmed as a single circumferential indication (SCI) of 0.30 volts by Plus Point. The detection of this flaw prompted sample expansion to 100% of paired dings in SG 2D, and 20% of all cold leg paired dings in the other SGs. There was also an axial crack near the circumferential crack,

at 16C+2.52". The combination of a circumferential crack at the upper ding of a paired ding with an axial crack at the lower ding of this pair triggered a verification of the measurement of the tube material between these two flaw signals. The two flaws are separated by over ¾". The circumferential indication with a nearby axial indication was selected for in situ leak testing as a new damage mechanism with an unusual characteristic. They were tested (in accordance with the EPRI Guidelines) together due to their proximity. The two indications together passed the leakage test with no leakage, and also passed the burst test (where a bladder was used).

4. Possible New Damage Mechanism

U-Bend Axially-Oriented ODSCC

The U-bend Row 1 Plus Point sample detected a small amplitude single axial crack near the apex of the tube at R1C2 in SG 2D. A subsequent examination with a high frequency Plus Point probe confirmed the indication. This indication had amplitudes of 0.17 and 0.19 volts on the mid-range and high frequency probe; however, multiple frequencies in both probes indicate that the indication initiates from the outer surface. Furthermore, the relative amplitude responses of the high frequencies and mid-range frequencies are consistent with an OD-initiated indication. The signal has a 300 khz approximate length of 0.25" and arc length of 30°. This tube was examined by Plus Point in 1998 (2RE06) with no degradation found. A re-review of this data revealed no previous indication. The detection of this defect resulted in expansion of the row 2 U-bend Plus Point examination from 20% to 100% in SG 2D. No other flaw indications were identified in the Row 1 and 2 U-bends during this inspection.

A non-quantifiable indication (NQI) was detected by bobbin at 11C+3.24" at the U-bend transition of SG 2A at tube R36C52. Follow-up Plus Point examination detected a short (0.22") single axially-oriented indication at this location. The phase angles of both techniques imply the indication initiated from the OD surface.

The Row 1 indication in SG 2D was in situ leak and burst tested per EPRI Guidelines to confirm that it does not challenge structural and accident-induced leakage performance criteria. Because the indication was in the U-bend, it was necessary to pressure test the tube from tubesheet to tubesheet. The tube was was successfully tested for leak (no evidence of leakage) and burst, confirming that structural and leakage integrity was not challenged. These two indications were most likely caused by the same mechanism as the freespan axial cracking discussed previously, but are treated separately here because they occurred in the U-bend during this inspection for the first time.

There was one instance in which a tube was preventively plugged due to an incomplete test. The U-bend portion of the tube at R1C57 in SG 2D would pass the Plus Point probe, but the motor unit was unable to spin the probe due to excessive friction. The U-bend portion of this tube was not tested in 2RE07, and in 2RE06, it appears to have been tested from the other leg. A single occurrence of this is not considered to be indicative of an hourglassing

problem, especially when it is considered that the STP tube support plates are constructed from stainless steel. The tube may have always been tight, and might again have been successfully tested had it been tested from the other leg.

5. Other Potentially New Damage Mechanism Carefully Evaluated

Volumetric Degradation at Expanded Preheater Baffle Plate Intersection

Prior to operation of the Model E steam generators at STP, a modification intended to lessen the likelihood of tube wear in the preheater baffle plates was implemented. The concern stemmed from the high velocity crossflow of the entering feedwater. Tubes encountered by the feedwater as it first enters the preheater were hydraulically expanded at the B (22C) and D (21C) plates. For many years, STP has included a sample of these expanded intersections in each inspection by rotating probe (both units) and has never before encountered degradation. Prior to this inspection, there were no industry reported occurrences of non-wear degradation at expanded preheater baffle intersections.

During 2RE08, a volumetric indication was identified by eddy current at the top of baffle plate 22C in SG 2C, tube R48C93. Based on this finding, the pre-planned 20% sample of preheater expansions was expanded to 100% in SG 2C. The eddy current data led the analysts to conclude the indication was an OD-originated flaw (with possible involvement in the expansion transition) and not deposits. The indication was examined by UT in order to better characterize its morphology. A much clearer view of the indication was obtained by UT. The UT examination showed no cracking and revealed the indication to be a small wear scar above the expansion transition of 8% depth. The R48C93 location is a prime area for foreign material impacts, as it is on the corner of the lower preheater baffle, in the first row of tubes encountered by the entering cross-flow feedwater. Loose part wear is not a new damage mechanism. Eddy current testing did not identify any possible loose parts at this location. The low wear depth of ~8% by UT examination gives reasonable assurance that the nature of this part will not result in higher wear on other tubes as this location is one of the highest flow locations in the steam generator. Although it may have been possible to justify removal of this indication from the list of defective tubes based on the UT results, it has been included with other OD volumetric indications in the defective tube count given in Table 1.

Cycle 8 Operating History

Unplanned Shutdowns

The operating history of Unit 2 in Cycle 8 included a number of unplanned shutdowns. One manual reactor trip from full power occurred very late in the cycle (3/1/01) due to a loss of all Circulating Water Pumps. In addition, four controlled shutdowns occurred for maintenance of plant equipment (1/4-6/00, 2/4-9/00, 6/2-8/00, and 2/4-9/01). There was a main turbine trip from low power during the startup from the February 2000 outage, and a reactor trip from low power during the startup from the February 2001 outage.

Possible Relevance to Growth Rates

Industry experience at Doel 4, Byron 1 and Braidwood 1 has led to some theories of cycle shutdown influence on degradation growth rates. No definitive industry consensus exists on this issue. One potential chemistry change during shutdown is the loss of oxygen control in the feedwater to the steam generators below about 30% power. The secondary system design at STP helps preclude this condition. At STP, a full flow feedwater deaerator provides the capability to maintain feedwater oxygen control during shutdown conditions. Oxygen control was maintained in the STP Unit 2 feedwater to the steam generators throughout the Cycle 8 shutdowns with one brief exception late in the cycle during the 2/4/01 power reduction. Based on the chemistry control during Cycle 8, shutdown oxygen control is not considered to be related to degradation growth rates experienced during Cycle 8.

End of Cycle Leak Rate

Total leak rate for all four Unit 2 steam generators at the end of Cycle 8 was near 35 gallons per day, as measured by the Condenser Air Removal System Radiation Monitor. The Nitrogen 16 (N16) radiation monitors mounted on each of the four main steam lines also indicated leakage in each of the generators with the highest leak rate being indicated in SG 2A, followed by SG 2D, SG 2C, and SG 2B. The individual leak rate indications on the N16 monitors are conservatively high when compared to total leak rate measurements due primarily to cross channel effects. (i.e., Shine from adjacent main steam lines will affect N16 monitor readings. This is an intended design feature that provides inherent confirmation of leak indication from a single steam generator.)

The primary-to-secondary leak rate monitoring instrumentation performed reliably during the cycle. Small changes in individual leak rate indicated on the respective N16 monitor were also evident on the condenser offgas monitor as a change. Using the relative ratios of the N16 monitor readings to apportion the combined leak rate as measured by the Condenser Air Removal System Radiation Monitor, leakage by generator at the end of Cycle 8 was about 10.5 gpd in SG 2A, 7.5 gpd in SG 2B, 8 GPD in SG 2C, and 9 gpd in SG 2D.

Overview of Primary to Secondary Leakage During Cycle 8

Initial indications of a measurable primary to secondary leak occurred during power ascension in Unit 2 on 6/10/00 when an increasing trend was noted on the Condenser Air Removal Radiation Monitor followed by a trend up on the common Steam Generator Blowdown Radiation Monitor. The N16 monitors for the 2B and 2C main steam lines then trended up as the unit approached 100% power. Steam Generator 2C had the highest indication, peaking at just over 2 GPD by N16. The N16 monitors then trended down over several days to near 1 GPD (total) and this leak rate remained stable until August. On 8/10/00, another increase was noted on 2C followed by an increase on 2B on 8/18/00. The 2B increase peaked at near 8 GPD by N16 and both monitors trended down over the next several days similar to the initial indication in June. By late August, SG 2A began trending up on the N16 monitor followed by 2D in early September.

After late September, the 2A N16 monitor was generally the highest of the four indications followed by 2D, 2C, and 2B. SG 2D was slightly higher than SG 2A during November as leakage from all four generators continued to trend slowly upward. By early February of 2001, the N16 indications ranged from about 6 GPD on 2A down to about 3.5 GPD for 2B. Total leak rate in early February was near 10 GPD. During this entire period of about eight months since the initial indication of measurable primary to secondary leakage, all four generators trended similarly. In accordance with our procedural requirements for monitoring primary to secondary leakage, we maintained a heightened awareness at the station, took extra samples to confirm our online radiation monitor indications, and adjusted our monitors to correspond to our grab sample measurements and current reactor coolant activity. As required by station procedures, an engineering evaluation of the stability of the leak indication and assessment of steam generator structural integrity was performed for steam generator leak rate of 15 gpd and again at 30 gpd.

Unit 2 experienced a downpower for a main generator hydrogen leak in early February. We entered primary-to-secondary leak rate Action Level 1 by our procedure on 2/10/01 during power ascension. Action Level 1 is required when total leak rate from all four steam generators equals or exceeds 30 GPD. After the expected peak following this startup, the leak rate trended down, consistent with the behavior of the leaks earlier in the cycle, until a plant trip on 3/1/01, which was caused by an electrical breaker failure in the switchyard. We continued in Action Level 1 through the subsequent power ascension and the scheduled shutdown for 2RE08, initiated on 3/6/01. The leak rate indications were once again trending downward at that time.

Chemistry

South Texas has implemented the latest revisions of the EPRI Primary to Secondary Leak Guidelines and the Secondary Chemistry Guidelines during Cycle 8. Chemistry control of the secondary has been consistent with previous cycles using ethanolamine for pH control and hydrazine for dissolved oxygen control. Full flow deep bed condensate polishers are utilized to remove trace impurities such as chloride and sodium from the condensate allowing us to maintain these impurities well below the guideline levels during power operation.

2RE08 Condition Monitoring and Operational Assessment

The preliminary tube integrity assessment that is required to be completed prior to entering hot shutdown (mode 4) per NEI 97-06, Revision 1, has been completed. The calculation of estimated accident-induced leakage (performed using the projected end-of-cycle voltage distribution) that is required to support Technical Specification Reporting requirement 4.4.5.5.d.1 has been completed. The calculation of conditional burst probability (also based on the projected end-of-cycle voltage distribution) that is required to support Technical Specification reporting requirement 4.4.5.5.d.5 has been completed. The Condition Monitoring assessment confirms that the structural integrity and accident-induced leakage performance criteria were met throughout Cycle 8. The preliminary Operational Assessment confirms that operation may proceed for at least ninety days of the upcoming Cycle 9 without exceeding the NEI 97-06, Rev. 1 performance criteria. A final Operational Assessment will be completed within ninety days.

Reports will be submitted to the NRC as required by NEI 97-06, Rev. 1 (Condition Monitoring final report) and by STP Technical Specifications (ninety day report per Generic Letter 95-05).

Cause of Tube Defects

The majority of the defective tubes detected in 2RE08 were the result of outside diameter stress corrosion cracking at tube-to-tube support plate intersections. This tube degradation mechanism is well known to the industry (as documented in the EPRI Steam Generator Reference Book, Chapter 12) for plants employing drilled-hole tube support plates and Alloy 600 mill annealed tubes, and has been addressed in NRC Generic Letter 95-05. Outer diameter stress corrosion cracking at tube support plate intersections is the result of tube susceptibility to stress corrosion cracking in the tube support plate crevice environment as confirmed by tube pulls at South Texas Units 1 and 2 as well as at other plants, and by the UT results from this inspection. The root causes of outer diameter stress corrosion cracking at tube-to-tube support plate intersections may be summarized as the selection of tube material (Alloy 600 mill annealed) and the design of the tube-to-tube support plate intersection locations (crevices resulting from drilled holes).

The remaining defective tubes were plugged primarily due to OD-initiated degradation. The cause of other OD-initiated degradation (primarily axial with some volumetric) is attributed to the tube material selection, and lack of care in handling tubing during manufacturing processes. For the circumferential indications at the hot leg top of tubesheet region, tube material selection in combination with residual stresses left by the tube expansion process are the primary causes.

Corrective Actions

The following actions have been or will be taken:

1. All defective tubes were plugged in accordance with Technical Specification requirements. In addition, an extensive preventive plugging effort was undertaken as described above.

2. In conjunction with the implementation of the 3 volt ARC, it was shown by bounding calculation that the C, F, and J support plates do not deflect significantly during postulated accident conditions, and can be relied upon to restrain indications at tube intersections with these support plates from burst. Also, as an added measure of conservatism against deflection, each of these plates was locked by tube expansion in a minimum of sixteen locations.

3. STP will replace the Unit 2 Model E steam generators with Model Delta 94 steam generators that employ Alloy 690 tubing material and broached tube support plates during the 2RE09 refueling outage.

References

1. Letter from S. E. Thomas to U. S. Nuclear Regulatory Commission, Document Control Desk, ST-NOC-AE-000698, dated 11/3/99, "Licensee Event Report 99-007 Regarding Steam Generator 2C Classified as Category C-3 During 2RE07"

2. Letter from S. E. Thomas to U. S. Nuclear Regulatory Commission, Document Control Desk, ST-NOC-AE-000405, dated January 19, 1999, "2RE06 Steam Generator Tube Voltage-Based Repair Criteria 90-Day Report"

3. Letter from Thomas W. Alexion to William T. Cottle, dated 9/22/99, "South Texas Project, Unit 2 - Review of Steam Generator Inspection 90-Day Report" (STP-assigned correspondence number ST-AE-NOC-000514)

4. Letter from Mohan C. Thadani to William T. Cottle, dated 3/8/01, "STP Unit 2 - Issuance of Amendment Revising the Technical Specifications to Implement 3-Volt Alternate Repair Criteria for Steam Generator Tube Repair" (STP-assigned correspondence number ST-AE-NOC-01000783)

TABLE 1

UNIT 2 STEAM GENERATOR 2RE08 INSPECTION RESULTS DEFECTIVE TUBE SUMMARY

	SG 2A	SG 2B	SG 2C	SG 2D	TOTAL
Total No. of Tubes	4,864	4,864	4,864	4,864	19,456
Number of Tubes Previously Plugged	209	232	249	231	921
Total No. of Tubes In-service = Number Inspected (100%)	4,655	4,632	4,615	4,633	18,535
# Defective Tubes @ 3 volt Tube Support Plates (ODSCC)	22	17	27	29	95
# Defective Tubes @ 1 volt Tube Support Plates (ODSCC)	1	3	5	2	11
# Defective Tubes - Axial ODSCC @ "Dings"	6	1	11	4*	22*
# Defective Tubes - OD Volumetric Indications	2	0	3	0	5
# Defective Tubes with OD Circumferential Ind. @ TTS	2	2	2	2	8
# Defective Tubes with Possible ID Circumferential Ind. @ TTS	1	0	0	0	1
# Defective Tubes - Axial ODSCC in U-Bend Region	1	0	0	1	2
# Defective Tubes, Circumferential OD Indications in "Paired Dings"	0	0	0	1*	1*
Total Number of Defective Tubes	35	23	48	38	144
% Defective	0.75%	0.50%	1.04%	0.82%	0.78%
Inspection Category	C-2	C-2	C-3	C-2	N/A

* - One tube had two defects with one in each of these categories.

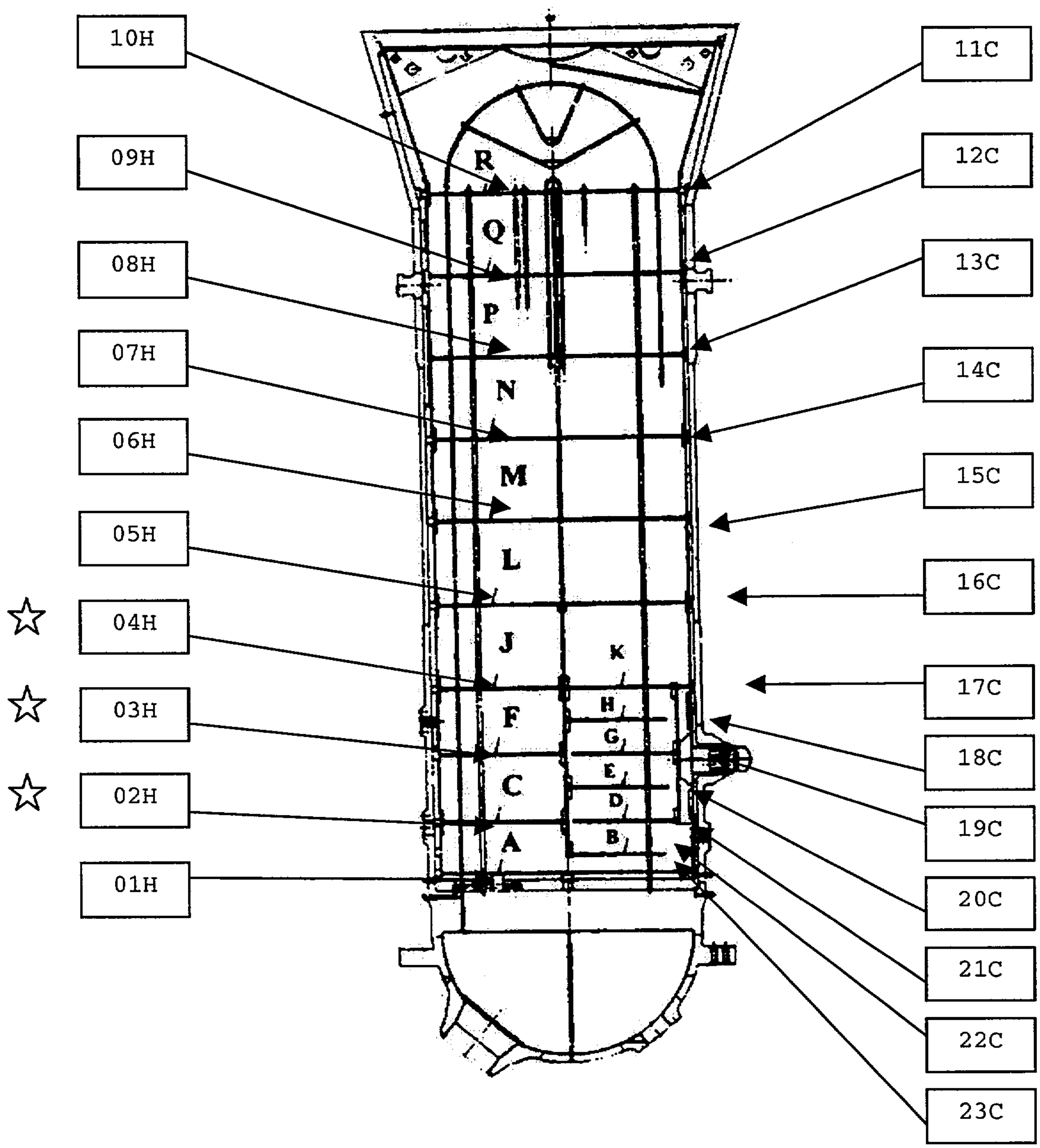
TABLE 2

UNIT 2 STEAM GENERATOR 2RE08 INSPECTION RESULTS
TUBE PLUGGING SUMMARY

	SG 2A	SG 2B	SG 2C	SG 2D	TOTAL
Total No. of Tubes	4,864	4,864	4,864	4,864	19,456
Number of Tubes Previously Plugged	209	232	249	231	921
Total No. of Tubes In-service = Number Inspected (100%)	4,655	4,632	4,615	4,633	18,535
Total Number of Defective Tubes	35	23	48	38	144
Preventive Plugging	189	153	164	168	674
Tubes Expanded to Lock 3 volt TSPs	22	18	18	18	76
Total Plugged in 2RE08	246	194	230	224	894
Total Plugging to Date	455	426	479	455	1815
Total % Plugged to Date*	9.35%	8.76%	9.85%	9.35%	9.33%

* South Texas design basis plugging limit is 10%.

FIGURE 1
TUBE SUPPORT PLATE IDENTIFICATION IN MODEL E SGs



NOTE: Plate A (01H/23C) is also known as the Flow Distribution Baffle.

☆ Three Volt ARC applies at these plates only.