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Age-Related Degradation of Steam Generator Internals Based on Industry Responses to Generic Letter 97-06[1]

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Abstract

This paper presents the results of an aging assessment of the nuclear power industry's responses to NRC Generic Letter 97-06 on the degradation of steam generator internals experienced at Electricite de France (EdF) plants in France and at a United States pressurized water reactor (PWR). Westinghouse (W), Combustion Engineering (CE), and Babcock & Wilcox (B & W) steam generator models, currently in service at U.S. nuclear power plants, potentially could experience degradation similar to that found at EdF plants and the U.S. plant. The steam generators in many of the U.S. PWRs have been replaced with steam generators with improved designs and materials. These replacement steam generators have been manufactured in the U.S. and abroad. During this assessment, each of the three owners groups (W, CE, and B&W) identified for its steam generator models all the potential internal components that are vulnerable to degradation while in service. Each owners group developed inspection and monitoring guidance and recommendations for its particular steam generator models. The Nuclear Energy Institute incorporated in NEI 97-06, "Steam Generator Program Guidelines," a requirement to monitor secondary side steam generator components if their failure could prevent the steam generator from fulfilling its intended safety-related function. Licensees indicated that they implemented or planned to implement, as appropriate for their steam generators, their owners group recommendations to address the long-term effects of the potential degradation mechanisms associated with the steam generator internals.

Background

The NRC staff issued Generic Letter 97-06[1], "Degradation of Steam Generator Internals," on December 30, 1997, to nuclear power plant licensees with pressurized water reactors (PWRs) to (1) reiterate previously communicated findings of damage to steam generator (SG) internals, namely, tube support plates and tube bundle wrappers, at foreign PWR facilities; (2) communicate recent findings of damage to SG tube support plates at a U.S. PWR facility; (3) emphasize the importance of performing comprehensive examinations of SG internals to ensure SG tube structural integrity is maintained in accordance with the requirements of Appendix B to 10 CFR Part 50; and (4) require licensees to submit information that will enable the NRC staff to verify whether their SG internals comply with and conform to the current licensing bases for their respective facilities.

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The reported foreign and U.S. experiences highlighted the potential for degradation mechanisms that may lead to tube support plate and tube bundle wrapper damage. The SG tube support plates support the tubes against lateral displacement and vibration and minimize bending moments in the tubes in the event of an accident. Support plate damage can impair its ability to perform this function and, thus, could potentially lead to the impairment of tube integrity. Vibration-induced fatigue could present a potential problem if tube support plates lose integrity, particularly in areas of high secondary-side cross flows. As previously noted in Information Notice (IN) 96-09[2], "Damage in Foreign Steam Generator Internals," tube support plate signal anomalies, found during eddy current testing of the SG tubes, may be indicative of support plate damage or ligament cracking. Certain visual and video camera inspections on the secondary side of an SG may also provide useful information concerning the degradation of SG internals. The generic letter also alerted licensees to the importance of performing comprehensive examinations of SG internals to ensure SG tube structural integrity is maintained.

Forty-one individual licensee responses involving 69 PWR units and five sets of owners group reports were submitted for staff evaluation[3]. The SGs currently operating in these 69 PWR units were grouped by their manufacturers or the owners groups, Babcock & Wilcox (B & W), Combustion Engineering (CE), and Westinghouse (W). The B&W Owners Group is divided into two groups: the B & W models with once-through SGs (OTSGs) supplied domestically by B & W, and the B & W replacement SGs by B&W International (BWI) of Canada. The three types of CE Owners Group SGs are considered in one group. The Westinghouse Owners Group SGs are divided in two groups containing four types of SG models: Westinghouse feed ring models with carbon steel tube support plates (TSPs), preheat models with carbon steel TSPs, feed ring models with stainless steel TSPs, and preheat models with stainless steel TSPs. Indian Point 2 was reviewed separately since they had the only W model 44 SGs in service at the time GL 97-06 was issued. In December 2000 they replaced their old SGs with model 44F units.

In response to GL 97-06, the SG owners groups have published specific technical information and guidelines related to their SG models. In addition, the Nuclear Energy Institute (NEI) has established a framework for structuring and strengthening existing programs in NEI 97-06[4], "Steam Generator Program Guidelines," and refers licensees to Electric Power Research Institute (EPRI) guidelines for the detailed development of some programmatic attributes. Section 3.9 of this document on the maintenance of secondary-side integrity states the following:

> *"Secondary-side steam generator components shall be monitored if their failure could prevent the steam generator from fulfilling its intended safety-related function. The monitoring shall include design reviews, an assessment of potential degradation mechanisms, industry experience for applicability, and inspection, as necessary, to insure degradation of these components does not threaten the structural and leakage integrity or the ability of the plant to achieve and maintain safe shutdown."*

The guidelines for an SG internals inspection program outlined by each SG owners group are comprehensive and intended to assist utilities in addressing the potential concerns in GL 97-06 on degradation. The guidelines are specific to each SG model and are targeted to inspect those portions of the SG internals judged to be susceptible to deterioration. The B&W Owners Group (B&WOG) developed inspection recommendations for their OTSGs for specific internal components and locations, while BWI of Canada outlined a very comprehensive program for their replacement SGs at the first refueling outage (RFO) inspection after installation of the replacement SGs. The CE Owners Group

(CEOG) presented recommendations for SG internals in their assessment reports. Finally, the Westinghouse Owners Group (WOG) included inspection guidelines for all of its various models currently in service. Using these guidelines and findings from individual plants or industry-wide activities, licensees already have implemented, or are planning to implement as appropriate to their SGs, the inspection programs recommended by their owners group[5].

Operating Experience

The owners groups performed safety and susceptibility assessments relative to the design and operating history of their models. These assessments provided reasonable assurance that tube integrity and decay heat removal (DHR) capability are not compromised by degradation of SG internals. The approach used included evaluations of degradation modes for structural components, chemical cleaning, and thermal-hydraulics factors associated with the SG design, manufacturing and operations. These assessments considered degradation at Electricite de France (EdF) plants[6], operating experience in U.S. plants, and indications of damage or susceptibility to other potential damage mechanisms that have not yet been seen by the industry, or that may be unique to a particular SG model. Chemistry data from licensees to determine the impact of chemistry on flow-accelerated corrosion (FAC) and other damage mechanisms were part of this evaluation. Finally, these reports contain recommendations for inspecting SG internals to monitor any future long-term potential degradation.

The scope of the evaluations encompassed all components of the SG internals including tubes and shell. These tubes and shell are regularly inspected as part of the reactor vessel pressure boundary, and any degradation is addressed by the SG tube-integrity program. The shell vessel welds are considered in the plant in-service inspection (ISI) program. Other SG internal components include steam outlet nozzle, baffle plate (shroud), tubesheets, tube support plates, feedwater header/spray nozzles, auxiliary feedwater nozzle, moisture separators, steam dryers, tube wrapper, small pipes and fittings, and other miscellaneous parts. Almost all internal components are made of either stainless steel or carbon steel. A notable exception is the SG tubes which are made of Alloy 600 or 690.

B&W Steam Generators

There are two groups of plants that have SGs manufactured by B&W. The first group includes seven reactor units whose nuclear steam supply systems (NSSS) were designed and supplied by B&W. The B&W plants have two reactor coolant system loops, each with two reactor coolant pumps and one once-through steam generator (OTSG). The second group of plants includes nine reactor units. All have replaced their original SGs with enhanced SGs designed and manufactured by B&W International of Canada. Unlike the first group, these replacement steam generators (RSGs) are B&W recirculating SGs.

<u>Once-Through Steam Generators</u>

Some peripheral tubes were damaged at Davis Besse 1 in 1981 and Oconee 3 in 1982 and leaked. This damage was caused by movement of the AFW internal headers and the brackets attaching these headers to the wrapper during operation. The AFW internal headers were subsequently stabilized and functionally replaced by external headers at these two plants. No movements or new indications of tube degradation have been observed at either plant since the internal AFW supply headers were stabilized. The original internal headers were left inside the SGs; and eddy current examinations are performed at each refueling outage to evaluate the status of peripheral tubes. The internal header also is visually inspected for movement inside the SGs. So far, no further evidence of movement or degradation of the internal AFW header or peripheral tubes has been noted. The internal header is visually inspected at Davis Besse 1 every 10 years as part of the plant technical specification requirements. Oconee 3 inspects the internal AFW header as part of a commitment made to the NRC in 1982. In addition, visual inspections of these internal headers and 100% eddy current bobbin coil inspections of the peripheral OTSG tubes have been conducted since 1995. No new degradation of the SG internals has been noted. Another visual inspection of the internal header is planned for the 3rd 10-year ISI interval.

Oconee 2 experienced higher corrosion rates during chemical cleaning than at the other plants, possibly due to higher concentration of magnetite in solution due to heavier deposit loading in the SGs. In response, an evaluation was made in 1996 to predict tube wear, TSP land wear, and operational corrosion rates as a function of increasing diametrical clearance due to chemical cleaning and operational corrosion and due to operational fretting-wear. The effects of increasing the gap on tube wear-rates and the margin to fluid elastic instability were evaluated using a combination of analytical and empirical techniques. The critical diametrical clearance was determined from the initiation of flow-induced vibration or fluid-elastic instability. Since chemical cleaning removes a small amount of base metal from the surface of each TSP and will affect the land areas of the broached tubes, the evaluation determined that the diametrical clearance for up to six chemical cleanings would have no significant effect on fluid-elastic instability nor random turbulent response. Although corrosion allowances were not exceeded at Oconee 2, an increase in the corrosion allowance for the TSP land is necessary should a second cleaning be required.

The following potential degradation mechanisms of OTSG internals were assessed. These potential damage mechanisms were not considered in the original design and, to date, have not been observed in operating plants.

(1) At Oconee 1 in 1979, there was an unusual pattern of tube dings at the 9th and 10th TSP level. Those dings at the 9th TSP appear to be in line with the wedge blocks, and at the 10th they are offset slightly clockwise from the alignment pins and wedge blocks. The actual cause of these dings is unknown. However, recent inspections do not show any appreciable increase in the number of tubes affected nor growth in the magnitude of the dings. Continued monitoring of these affected regions during future inspections was recommended.

(2) The manway covers in the TSPs are made of the same material as the TSPs (SA-515, Gr. 70 CS or SA 212-B CS). They were assembled using 6 half-inch, 13 UNC-2Ax1 ½ inch cap-screws that were tack-welded at final assembly. Should these covers become loose, they could cause wear which would be detected by eddy current inspection of the tubes.

(3) There are four ½ inch hex bolts in the shroud access cover (elliptical). On all of the OTSGs except Crystal River 3, the bolts are tack-welded. Since there are no loads that would directly cause these bolts to back out at Crystal River 3, the licensee believes there are no potential damage mechanisms associated with the shroud cover.

(4) The tie rod to lock-nut welds in an OTSG serve the same function as in the EdF SGs. No structural mechanisms in the OTSG design were identified that would contribute to failure of the tie-rod to lock-nut weld.

Replacement BWI Steam Generators

B&W RSGs are uniquely vulnerable to positioning of the U-bend components which could cause contact between peripheral tubes. The U-bend structure, which is free to move with the U-bend during operating transients, is supported by the peripheral tubes by "L" and "J" shaped elements called J-tabs. It was determined that the positioning of some of the J-tabs during manufacture may cause contact between certain pairs of vertically adjacent peripheral tube U-bends. Also, peripheral tubes in contact during SG operation may be subject to flow-induced vibration fretting wear at their point of contact. However, based on further assessment, B&W stated that fretting wear will not result in unacceptable tube-wall reduction over a projected 40 to 60-year operating life. Another degradation mechanism assessed relates to build up of tube bundle deposits and the potential for bridging of deposits between nearby tubes. Assuming a minimum gap and no vibratory contact, bridging could occur in approximately 10 years. Based on corrosion studies on thermally treated alloy 690 tubing, the B&WOG concluded that no additional damage will result from such bridging in the U-bends.

Inspections conducted at three plants (i.e., Millstone 2, Ginna, and Catawba 1) have indicated that unfavorable proximity exists (less than desired clearance or possible contact) for a few tubes on several RSGs. Therefore, monitoring the proximity of tubes in this region during subsequent inspections should be performed until the effects of this degradation mechanism on the tube integrity is better understood. The routine ongoing outage cycle inspections by eddy current tests and secondary side visual inspections can be used.

CE Steam Generators

Out of the 15 plants with CE-designed Nuclear Steam Supply Systems, 11 plants still have CE-designed SGs. ANO-2 replaced both of its SGs with Westinghouse Model D109 in December 2000. However, the response to the GL by ANO-2 addressed only the original CE-designed SGs. Of the other three plants, Maine Yankee is permanently shutdown, and both Millstone 2 and St. Lucie 1 replaced their original SGs with new SGs manufactured by B&W International of Canada. Of the 11 plants still using CE SGs, Palisades replaced its original SG with a somewhat newer model CE-designed SGs in March 1991. Based on the differences in the tube support design of the 12 CE-designed plants (including ANO-2), the CE-manufactured SGs fall into three categories: Type 1 - SGs with both carbon steel eggcrates and drilled hole tube support plates; Type 2 - SGs with carbon steel eggcrates only; and Type 3 - SGs with stainless steel eggcrates only.

The CE-designed SG has a shroud (or baffle) which separates the incoming feedwater and recirculating flow from the heat transfer tubing area. The shroud is thicker than EdF SGs and also serves as the main load path for the eggcrate and tube support plates. The cylindrical shroud can handle the lateral loadings due to seismic forces on the tubes and tube supports. The shroud is welded to 16 lower shell lugs above the tubesheet and thus it expands from the bottom similar to the tubes. The shroud has additional lateral restraint supports located near the bundle's center and at the top, which are designed to allow axial expansion.

During the late 1960s and early 1970s SGs manufactured by CE had drilled hole carbon steel tube support plates (TSPs) in the tube bundle at upper elevations. The TSPs became corroded in these early models, and this was attributed to water chemistry and ingress of balance-of-plant contaminants, such as copper. Corrosion of the carbon steel TSPs resulted in tube denting, TSP swelling, damaged supports, and damaged tubes. Analyses showed that removing the outer portion of the drilled TSP, and cutting the plate loose from the shroud would minimize the possibility of denting and damaging the tubes, by relieving the stresses in the TSPs. Therefore, the outer rims of the TSPs were removed, and the plates were detached from the shroud at all the plants with drilled TSPs, except Calvert Cliffs 2 (since denting was not significant there). Eliminating the stress concentrations in the TSPs delayed the onset of ligament cracking in the TSP. The only way to eliminate ligament cracking in these plants was to prevent denting of the tubes by removing the cause of support plate corrosion. Other mitigating actions taken at the time included reducing the ingress of contaminants, reducing in-leakage of air, replacing copper-containing components, and treating with boric acid. These actions, together with staking or plugging some damaged tubes, essentially halted denting.

Flow-accelerated corrosion (FAC) was identified as an operational damage mechanism for the eggcrate tube supports and was observed at the San Onofre Nuclear Generating Station (SONGS) Unit 3. FAC was attributed to changes in secondary side fluid parameters caused by the buildup of deposits on the SG tubes (i.e., fouling of tube bundles). This buildup increased fluid velocities and lowered pH to levels where rapid FAC occurred. The fouling of the tube supports appeared related to iron transport into the unit through the feedwater (FW) system. At SONGS 3, major FAC effects were found in the peripheral regions of tube support strips of the uppermost eggcrate supports during the 1997 refueling outage (RFO). The thin tube support strips (.09" thick) expose a large surface area to fluid flow and are vulnerable to corrosion.

Westinghouse Steam Generators

Over forty operating reactor units currently have Westinghouse (W) SGs, involving about a dozen different W-designed SG models. The earlier W-designed SG models (e.g., Models 24, 27, 33, 44) were followed by 51-series and D-series SGs. Several licensees have replaced their original SGs with enhanced models (44F, 51F, and 54F). These enhanced models use hydraulically expanded, thermally treated Alloy 600 tubing and 405 stainless steel tube support plates (TSPs) [except for model 54F, used at Cook 2 and Indian Point 3 which has thermally treated Alloy 690 tubing].

WOG evaluated all its SG models in two groups. The first group includes the 51-series SGs consisting of Westinghouse models 51, 51M, 51F, and 54F. The 51-series SG designs are the most similar to the EdF units described in the GL. Westinghouse also included two other replacement SG designs, the Delta 47 (Δ47) and Delta 75 (Δ75) in these evaluations because of a stated "similarity in design." The second group includes W SG models 44F, F, D3, D4, D5, and E2.

Westinghouse models 51, 51M, 51F, 54F, Δ47 and Δ75

Based on the survey responses, erosion-corrosion of moisture separators and the feed ring/J-tubes, and cracking of transition cone girth welds were observed in some SGs. Cracking of TSP ligaments associated with models 51 and 51M (with carbon steel TSPs) was also observed in some SGs. The TSP flow holes and ligaments are believed to be susceptible to erosion-corrosion damage for models 51 and 51M SGs, while the TSP ligaments in models with stainless steel TSPs (51F, 54F, Δ47, or Δ75) have low susceptibility to cracking. The wrapper near supports in all SGs in this group has low susceptibility to cracking and hence to wrapper drop.

Overall, WOG's conclusions on the 51-series SGs include the following:

(1) SG designs (models 51 and 51M) that have fabrication access openings in the TSPs, called patch plates, secured by plug welds are susceptible to inspection indications,

(2) There is no susceptibility to TSP ligament cracking near the wedge supports,

(3) There is no susceptibility to wrapper drop or cracking of the wrapper at the lower supports,

(4) The potential for TSP flow hole erosion-corrosion does not exist in SGs with stainless steel TSPs and is very low in

units with carbon steel TSPs, and

(5) Missing pieces of carbon steel TSP ligament and ligament indications (cracks) are likely the result of out-of-tolerance drilling alignment during manufacturing.

Westinghouse models 44F, F, D3, D4, D5, and E2

At Shearon Harris, tube wear was detected on several tubes in row 49 just above the B plate, on the cold leg side of one Model D4 SG. The foreign objects responsible for the wear originated from erosion/corrosion on the vertical support ribs in the water box area where two cylindrical pieces were retrieved. No erosion/corrosion of the wrapper, impingement plate, target plate or impingement plate to target plate weld was seen. Westinghouse concluded that any rib pieces that separated from the water box would be small, and that the erosion/corrosion pattern occurring in the ribs will gradually enlarge the original 1" holes, so that the affected flow holes would eventually coalesce.

In the feed ring SG design, thinning of carbon steel J-tubes has prompted some plants to replace them with alloy 600 J-tubes which are more resistant to erosion-corrosion. In the preheat SG design, erosion-corrosion was observed on some vertical support ribs welded to the outside of the SG impingement plate in the waterbox area. In South Texas Unit 1 portions of the waterbox side ribs and support ribs were eroded away, resulting in loss of the intended perforated structure due to enlargement and coalescence of the flow holes. The licensee stabilized the affected SGs by plugging several tubes. Eddy current testing (ECT) of peripheral and T-slot tubes within the preheater is being performed at each refueling outage (RFO).

At Watts Bar, one end of the blow-down pipe was severed in two Model D3 SGs. Further analysis indicated that overstress in the fillet weld, where failure occurred, was caused during the manufacture and hydro-testing of the SGs. Evaluation of the clearances and flow conditions showed that consequential damage to adjacent tubes is not expected since the flow velocities in this region are low and the clearances are large. We note the unique design of the blow-down pipe for the Model D3 SG; other preheat SG designs do not utilize a continuous blow-down pipe extending the length of the tube lane.

Based on the survey results, erosion-corrosion in moisture separators and feed ring/J-tubes of model F and 44F and in waterbox of models D3, D4, and E2-TGX were observed in some SGs. Also, cracking in the transition cone girth weld of model F and 44F was observed in some SGs. The TSP ligaments and the wrapper near the supports of models F and 44F have a low susceptibility to cracking. For models D3, D4, and E2-TGX, the moisture separators and the TSP flow holes/ligament are susceptible to erosion-corrosion, while the TSP ligaments are susceptible to cracking. The wrapper near the supports and transition cone girth weld have low susceptibility to cracking. For models D5 and E2-THX, the moisture separators and the waterbox are susceptible to erosion-corrosion, while the TSP ligaments, the wrapper near the supports, and the transition cone girth weld have low susceptibility to cracking.

Based on the W evaluation, all models of SGs in this group, are susceptible to the following types of damage that may affect SG tube integrity:

(1) Erosion-corrosion of the moisture separators and other steam drum components in all SG models,

(2) TSP flow hole erosion-corrosion applicable to SG Models D3, D4, and E2-TGX with carbon steel TSPs and round flow holes,

(3) Erosion-corrosion of water box internal components in the preheat design models (D3, D4, D5, E2-TGX, and E2-THX) and

of feed ring and J-tubes in the feed ring design model SGs (F and 44F),

(4) TSP ligament cracking near the wedge supports in Model D3 SGs,

(5) TSP ligament cracking near the patch plates in Models D3, D4, Early F, and E2-TGX SGs that have patch plates and plug welds securing them on the TSPs, and

(6) Cracking of the transition cone girth weld in Model 44F SGs.

Indian Point 2 with Westinghouse Model 44

At the time of the GL 97-06 issuance, Indian Point 2 (IP2) had feed ring model 44 SGs which were in service since the start of commercial operation of IP2 in 1974. They were manufactured with mill-annealed alloy 600 tubing, carbon steel tube support plates with drilled holes, and partial depth rolled tube-to-tubesheet joints. Early in the operating life of the IP2 SGs during the mid-seventies, general corrosion of the carbon steel TSPs and tubesheets resulted in a buildup of corrosion products in the annulus between the tubes and the TSPs, and/or between the tubes and the tubesheet. This buildup squeezed the tubes enough to cause permanent, plastic deformation at the TSP and tubesheet areas. As a result, all four SGs at IP2 experienced significant deformation of the tubes, commonly referred to as "denting." By enhancing the quality of the secondary water and implementing other mitigating actions, the licensee managed to bring tube denting largely under control. However, this denting led to extensive in-plane deformation in the TSPs and cracking of the TSP ligaments. One manifestation of TSP deformation was the distortion of the initially rectangular flow slots located along the open lanes separating the hot- and cold-leg sides of the tube bundle. The deformation in the TSP transformed the shape of the rectangular flow slots into hourglass shaped ones, typically referred to as "hourglassing." Much of this deformation process at IP2 occurred in the late 1970s and early 1980s and was readily visible during each subsequent inspection outage.

To ensure that the NRC would be alerted to any significant change in the status of denting or hourglassing of the uppermost TSPs, several requirements were added to the IP2 plant technical specifications. Through several inspection efforts and subsequent staff interactions with the licensee that occurred in the late 1970s and early 1980s, some of these added specifications required that the licensee (1) provide an evaluation to address the long-term integrity of small radius U-bends beyond row 1 within 60 days of any significant hour-glassing of the upper support plate flow slots, (2) report a significant increase in the rate of denting, and (3) plug tubes that do not permit passage of a 0.610 inch diameter probe. Throughout the 1980s and 1990s, the licensee performed its SG inspections in accordance with these requirements.

During the SG inspection in May 1997, IP2 reported the following active degradation mechanisms in the SGs: wear at the anti-vibration bars (AVBs); outside-diameter stress corrosion cracking (ODSCC) and pitting in the sludge-pile region (i.e., the area above the top of the tubesheet and below the first TSP); ODSCC and intergranular attack (IGA) in the crevice between the tubes and the tubesheet; and primary-water stress corrosion cracking (PWSCC) at the tubesheet roll transitions and in a low row U-bend. This was the first time that PWSCC was identified in a low row U-bends. During subsequent plant operation the licensee detected a primary-to-secondary leak through the SGs by tritium surveys, sampling condenser off-gas, and other monitoring methods. This leak rate slowly increased from 0.5 gpd (gallon per day) in September 1998 to between 3 and 4 gpd in January 2000. On February 15, 2000, IP2 was shutdown due to excessive tube leakage in one of its SGs (i.e., SG 24). After extensive studies on the root causes of this incident and efforts to justify continued operation with the original SGs, the licensee replaced all four SGs with model 44F SGs containing thermally treated alloy 600 tubing.

Visual inspections were conducted after the 2000 event to assess the general condition of the TSPs and SG wrapper. Where accessible to the video camera, in-plane deformation (growth) of the TSPs, due to denting, was observed to have caused the support plates to be in contact with the wrapper, except in the near vicinity of the wedge supports. The reaction loads at the periphery of the TSPs maintained the plates in a high state of compression and the licensee, based on a detailed structural analysis, demonstrated that they were still capable of providing adequate lateral support to all unplugged tubes under operating and postulated accident conditions. All wedges and welded connections were observed to be in good condition. The licensee reported that there was no visible deterioration of the wrapper and the wrapper had not dropped from its earlier position.

Age-related Degradation of Steam Generator Internals

Tube Support Plates

Ligament Cracking

Several domestic plants discussed their experience with tube support plate indications in their GL responses. During the early years of operation, ligament cracking of drilled-hole carbon steel tube support plates resulted from corrosion of the tube support plates. Buildup of corrosion products between the tubes and support plates caused tube denting and, in some cases, tube support plate cracking. Licensees brought this degradation mechanism under control by a series of actions, including design modifications and improvements in chemistry controls to mitigate tube support plate corrosion. In other cases, licensees traced indications of tube support plate ligament cracking to misdrilling of flow holes that occurred during manufacturing. Lastly, some licensees linked tube support plate indications to the patch plate plug welds. In all cases, licensees traced these tube support plate indications back to initial or early operation inspections and have confirmed no new indications or progression of old indications. Licensees monitor these indications through their eddy current inspections of the tubes. Cracking of a series of adjacent ligaments could potentially occur and lead to failure and dropping out of a portion of the TSP with the consequential loss of tube support in this region. Licensee actions in response to this issue appear appropriate in that the licensees have implemented corrective actions to prevent new occurrences of tube support plate cracking and are continuing to track existing indications through their regular, periodic eddy current inspections.

This degradation mechanism appears limited to those SGs with drilled-hole carbon steel tube support plates. Broached and lattice-type supports appear much less susceptible, due generally to their more open and flexible design. Stainless steel supports of any type also appear much less susceptible because of their greater resistance to corrosion. Although eddy current inspection techniques are not qualified to detect and disposition indications associated with broached and lattice-type supports, licensees are able to detect the presence or absence of such supports through eddy current testing. No instances of missing supports have been identified in the U.S. In addition, licensees have performed numerous secondary-side visual inspections, and no instances of cracking in broached or lattice-type supports have been identified.

Erosion-Corrosion

Tube support plate degradation at EdF plants may be linked to the water chemistry that consisted of low hydrazine concentration and operation with ammonia at a low pH. All domestic plants operate today on an all-volatile treatment feedwater chemistry, which provides greater protection against erosion-corrosion than an ammonia water chemistry. Numerous eddy current and secondary-side visual inspections appear to support industry conclusions that erosion-corrosion of tube support plates is not an active degradation mechanism at any domestic facility. SGs with stainless steel tube supports are not susceptible to this degradation mode. However, erosion-corrosion is a potential issue for SGs with carbon steel lattice-type support structures.

Erosion-corrosion of the carbon steel lattice-type support structures has occurred in domestic SGs because of severe tube bundle fouling conditions. The applicable owners group reports addressed this potential degradation mechanism and developed recommendations for secondary-side visual inspections to verify the condition of the tube supports based on tube bundle fouling parameters (e.g., loss of secondary-side steam pressure). Assuming licensees implement the owners group recommendations, the recommended inspection actions appear appropriate because (1) the inspections will take place when conditions appear conducive to erosion-corrosion, (2) even under such conditions, there is substantial margin in the allowable amount of erosion-corrosion due to the robustness of the design, and (3) the inspection techniques (i.e., secondary-side visual inspections) may be relied upon to detect such conditions.

Wrapper Damage

All owners groups stated that the identified wrapper degradation mechanisms are not applicable owing to design differences in the wrapper-shell attachment (e.g., thicker wrapper, use of full penetration welds). Some licensees have inspected their wrapper assembly and found no degradation. Most licensees rely on their routine foreign object searches and sludge lancing to alert them to conditions of wrapper drop. The equipment for these operations apparently cannot be inserted unless the wrapper is properly aligned.

Feedwater System and Other Damage

Some licensees provided plant-specific information related to internals degradation other than the degradation discussed in the generic letter. Such instances included degradation from water hammer events, erosion of components that are part of the feedwater system, and tube proximity problems in the U-bend region. Licensees discovered these problems with eddy current testing and ultrasonic inspection of the tubes and feedwater equipment, visual inspections of the secondary side of the tube bundle and steam region, and routine foreign object search and sludge lancing procedures.

Summary and Conclusions

Few domestic plants found the foreign and domestic experiences discussed in Generic Letter 97-06 directly applicable to their SGs. Only those SGs with carbon steel drilled-hole type supports or carbon steel lattice bar type supports are susceptible to tube support plate ligament cracking or erosion-corrosion, respectively. Actions taken in response to these two degradation mechanisms, as discussed in the owners group reports, appear adequate. A number of other degradation mechanisms, not discussed in the generic letter were discussed by licensees and owners groups in their responses to the generic letter. These include degradation from water hammer events, erosion-corrosion of feedwater system components, and tube proximity problems in the U-bend region. Licensees identified these issues through their current inspection programs and either resolved these issues through their internal corrective action programs or are monitoring them through their inspection programs.

In response to the Generic Letter, the owners groups considered design, fabrication and manufacturing techniques, plant operating history, and visual and eddy current inspection findings to determine the susceptibility of specific SGs to internals degradation and thus developed a number of recommendations. On the basis of the owners group recommendations, all U.S. PWR plants have implemented or plan to implement, as appropriate to their SGs, the recommendations of their owners group to improve inspection and monitoring for the degradation of the SG internals. Programs in place include sludge lancing, chemical cleaning, and pressure pulse cleaning; foreign object search and retrieval; visual and/or ultrasonic inspections of components in the upper bundle region, steam drum section, water box, and feedwater section of the SG; and visual and/or eddy current inspections of the tubes and tube support plates. Licensees perform most of these activities routinely. These activities appear effective in detecting and managing internals degradation based on operating experience to date.

Concurrent with the Generic Letter, the Nuclear Energy Institute added a requirement to its NEI 97-06, "Steam Generator Program Guidelines," to monitor secondary-side components if their failure could prevent the SG from fulfilling its intended safety-related function. Licensees have committed to upgrade their SG programs by implementing the recommendations suggested by the owners groups.

Licensees' current and planned activities with respect to internals appear to provide reasonable assurance that tube integrity and decay heat removal capability is not compromised by internals degradation.

References

1. NRC Generic Letter 97-06, "Degradation of Steam Generator Internals," December 30, 1997.

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