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NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
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NRC INFORMATION NOTICE 97-88: EXPERIENCES DURING RECENT STEAM GENERATOR INSPECTIONS

Addressees

All holders of operating licenses for pressurized-water reactors (PWRs) except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees about findings from recent inspections of steam generator tubes and secondary-side internal components. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances

Recent inspections of steam generator tubes and secondary-side internal components have identified a number of concerns related to the degradation of these components. The relevant findings associated with these concerns are discussed below.

Degradation of Secondary-Side Internal Components

In May 1997, the licensee for the Shearon Harris Nuclear Power Plant found that four perforated, carbon steel ribs in a steam generator had been extensively damaged. The ribs are welded to the feedwater impingement plate which shields the steam generator tubes from direct impact of the feedwater flow. The licensee concluded that the high flow velocities of the feedwater had eroded the ligaments between the perforations on the ribs.

During the spring 1997 refueling outage, Southern California Edison Company, the licensee for the San Onofre Nuclear Generating Station, Unit 3 (SONGS-3), discovered degradation of the steam generator tube eggcrate supports. The damage was confined to the periphery of the supports. The damage existed in both steam generators on both the hot-leg and cold-leg sides but was more extensive on the hot-leg side. The licensee concluded that excessive deposits on the steam generator tubes and supports were responsible for changes in flow velocities and water chemistry on the secondary side of the steam generator. The erosion/corrosion damage mechanism resulting from these changes subsequently damaged the eggcrate supports. The deposits were removed by chemical cleaning during the outage. With nominal secondary-side properties restored, further erosion/corrosion is not expected because of better control of secondary-side chemistry conditions.

Eddy current inspection of steam generator tubes gathers limited information on secondary-side conditions that could challenge the structural and leakage integrity of tubes. The erosion of secondary-side steam generator components could potentially lead to loose parts. In addition, erosion of the eggcrate supports as observed at SONGS-3 could reduce the lateral restraint of the tubes and could increase the potential for flow-induced vibration of the tubes. Because of these experiences, other utilities have visually inspected the secondary side of steam generators to assess the integrity of internal components. Such inspections could promote early detection and mitigation of secondary-side

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component degradation.

Deficiencies in Inservice Inspections

Qualification of Eddy Current Depth Sizing Techniques

Attempts to qualify eddy current techniques for estimating the depth of intergranular attack (IGA) and stress-corrosion cracking (SCC) in steam generator tubes have had limited success. Entergy, the licensee for Arkansas Nuclear One, Unit 1 (ANO-1), developed a technique to estimate the depth of volumetric IGA in once-through steam generator (OTSG) tubes. The technique was qualified using data primarily from Crystal River Nuclear Plant, Unit 3 (CR-3) tube specimens and supplemented with data from ANO-1 tube specimens. The licensee applied the technique to IGA indications in the upper tubesheet crevice. Destructive examination of several tubes revealed that the technique underestimated the depth of the indications by as much as 50 percent of through-wall depth. The tube specimen data obtained from CR-3 contained indications from the lower regions of the tube bundle above the lower tubesheet. The environment in that region differs considerably from the environment in the upper tubesheet crevice. Because of the differences in the environments in which the IGA degradation developed and the licensee's reliance on data obtained from CR-3, the resulting sizing technique developed in the qualification process yielded nonconservative depth estimates when applied to the degradation in the ANO-1 OTSGs.

Entergy's experience illustrates some of the potential difficulties in qualifying and applying eddy current depth-sizing techniques. Because eddy current inspection methods are sensitive to a number of variables, the qualification process should consider all of these variables. Although Entergy assumed that the IGA indications from ANO-1 and CR-3 were of similar morphology, other factors, such as the conductivity of the degradation, were not considered in the development of the sizing technique. Also, because the tube specimens were obtained over a period of many years, it may have been appropriate to address changes in the degradation that may have occurred over time. Validation of developed depth-sizing techniques through sizing and subsequent destructive examination could address each of these factors.

Inaccuracies in the Location of Indications

In June 1997, Duke Power shut down William B. McGuire Nuclear Station, Unit 2, because of an increasing primary-to-secondary leak. A steam generator tube was leaking approximately 13.2 cm [5.2 inches] above the second cold-leg tube support plate. During the preceding refueling outage, the general bobbin coil probe inspection identified an indication in this same area. At that time, in accordance with procedure, the licensee inspected the area with a rotating pancake coil (RPC) probe from 12.7 cm [5 inches] below to 2.5 cm [1 inch] above the location at which the bobbin coil probe detected an indication. The RPC probe inspection did not confirm the indication and the tube was returned to service. After the primary-to-secondary leak occurred and was located, the licensee reexamined the inspection data from the previous refueling outage and concluded that the RPC data were actually not acquired over the area of interest. Although the area containing the degradation should have been, and appeared to have been, inspected with the RPC probe, the measurement from the second support plate to the indication location was inaccurate which resulted in the indication not being inspected.

Several licensees have provisions in their eddy current inspection program that reduce the possibility of leaving a defective tube in service as was done at McGuire Unit 2. Instead of attempting to position a rotating probe at a particular location relative to a support, data are collected between two support locations that bound the section of tubing containing the indication which should guarantee that the area of interest is inspected. Other methods that minimize probe positioning inaccuracies include: (1) using axial encoders during data acquisition, (2) establishing consistent settings in the data analysis software, and (3) using sharp reflectors sufficiently spaced in the calibration standard to more accurately calibrate the probe translation speed.

Potential Inability to Detect Cracks at Locations with Dents Less Than 5 Volts

To better detect cracks at dented locations, the Electric Power Research Institute (EPRI) recommends the use of supplemental eddy current probes (e.g., Cecco or RPC) on dents greater than 5 volts. At Sequoyah Nuclear Plant, Unit 1; Diablo Canyon Nuclear Power Plant, Unit 1; and Maine Yankee Atomic Power Station, inspection of dents less than 5 volts with RPC probes have detected crack indications that were not detected with the bobbin coil probe. The dents were at tube support plate intersections. The indications initiated from both the inside and outside diameter of the tube and were both circumferential and axial in nature. Apparently, eddy current signal distortion from the dents hindered detection with the bobbin coil probe.

These inspection findings call into question the adequacy of the 5-volt threshold recommended by EPRI. The licensee for Sequoyah Unit 1 has surveillance requirements in the plant's technical specifications which require an RPC inspection of dents less than 5 volts. Such requirements may improve the ability to detect cracks in tubes with dents less than 5 volts.

Indications Identified in Welded Tubesheet Sleeves

In the 1995 refueling outages at Zion Nuclear Plant, Units 1 and 2, eddy current inspections of welded tubesheet sleeves identified a number of indications that were not detected by visual or ultrasonic inspection methods. The sleeved tubes containing eddy current indications were returned to service on the basis that the visual and ultrasonic inspections did not confirm the indications. This was documented in a nonconformance report, however, a formal safety evaluation to assess the significance of the eddy current indications was not performed. In January 1996, inspections of welded sleeves at the Prairie Island Nuclear Plant, Unit 1, found 61 indications similar to those found at Zion. Metallurgical evaluations of sleeve/tube assemblies removed from Prairie Island revealed that the indications were the result of weld conditions caused by improper surface preparation during the sleeve installation process. Subsequent inspections of sleeve welds at other plants with welded tubesheet sleeves showed similar indications.

The initial sleeve weld acceptance criteria are based primarily on an ultrasonic test examination to demonstrate an adequate sleeve weld joint. Although indications were detectable using eddy current methods, this testing was performed only to provide a baseline for future examinations. The experience with welded sleeves indicates a combination of visual, ultrasonic, and eddy current techniques may be needed to provide comprehensive coverage of areas susceptible to defects. Although the alternative inspection techniques did not identify the presence of the eddy current indications at Zion, the significance of the indications detected by eddy current was indeterminate because the nature of the degradation and the sensitivity of visual and ultrasonic inspection techniques to the indications was unknown.

The experience with welded CE sleeves highlights the importance of adequately qualifying the capabilities of each inservice inspection technique and addressing the root cause of new modes of steam generator tube degradation. Because the capabilities of the ultrasonic and visual inspection techniques to detect the weld zone defects had not been assessed, negative inspection results (i.e., lack of confirmation) should not have been considered sufficient evidence to conclude that the sleeved tubes with the eddy current indications were acceptable per the plugging limits specified in the technical specifications.

High Voltage Growth of Outer-Diameter Stress Corrosion Crack (ODSCC) Indications

The Joseph M. Farley Nuclear Plant, Unit 1, applies a voltage-based steam generator tube repair criteria to ODSCC indications conforming to the guidance in NRC Generic Letter (GL) 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside-Diameter Stress-Corrosion Cracking." During a routine tube inspection in April 1997 at Farley Unit 1, data analysts identified a bobbin coil indication with a voltage amplitude of approximately 14 volts. The voltage of the indication was 1.46 volts at the previous inspection and was not anticipated based on an operational assessment completed during the prior refueling outage. The operational assessment also did not predict the distribution of higher voltage indications identified during the subsequent inspection. Because the operational assessment underestimated the magnitude and number of higher voltage indications, the calculated end-of-cycle (EOC) conditional tube burst probability was lower than would be calculated using the actual inspection results.

Commonwealth Edison (Com Ed) similarly identified a number of higher voltage ODSCC indications in an inspection at Braidwood Station, Unit 1, that were not anticipated based on the licensee's previously completed operational assessment. Consequently, the EOC main steam line break (MSLB) tube leakage predicted as part of the assessment (26.5 liters per minute (lpm) [6.99 gpm]) was lower than the leak rate predicted using actual EOC inspection results (45.5 lpm [11.5 gpm]). At a meeting with the NRC on July 23, 1997, Com Ed presented its conclusion that the voltage growth of ODSCC indications is dependent on the initial voltage of the indications. GL 95-05 recommended a methodology for projecting the distribution of indications (i.e., the number and voltage) which assumed that the growth rate for indications left in service was independent of the initial indication voltage. The use of this assumption was contingent upon the licensee having demonstrated that the methodology predicted distributions of indications which were conservative when compared to operating experience. Using voltage-dependent growth rates, Com Ed was able to improve the accuracy of the EOC MSLB tube leakage estimation.

The findings discussed above identify instances where the methodology discussed in GL 95-05 was shown to be nonconservative with respect to operating experience. Braidwood 1 is unique in that it has a voltage-based criteria value greater than other licensees which permits higher-voltage indications to remain in service. However, the nonconservatism identified by Com Ed may have implications for other licensees using voltage-based repair criteria. Licensees utilizing the methodology may wish to address the implications of this issue in future operational assessments.

Continued Degradation Growth in Plugged Tubes

Eddy current inspection of tubes recently removed from the retired McGuire, Unit 1 steam generators found that the bobbin coil voltage for indications had increased even after the tubes were plugged. Of the 12 crack-like indications examined, 10 had apparently initiated from the outside diameter (OD) of the tube and 2 from the inside diameter. The inspections revealed increases in the bobbin coil voltages ranging from 0.3 to 6.1 volts since the tubes had been plugged. Increases in RPC voltage were also noted. Because the results are preliminary and are based entirely on nondestructive inspection data, it is not certain whether the indications had grown after the tubes were plugged, however, these results suggest that the indications did change in some way after the tubes were plugged.

During the spring 1997 refueling outage at Braidwood 1, Com Ed found that 49 of 85 "locked" tubes (also plugged) had circumferential cracks at the tubesheet expansion transition area. The tubes had been locked by expanding them above and below certain tube support plate intersections in support of the use of voltage-based repair criteria. Inspections of the tube expansion-transitions completed before the plugging verified that no indications were present in the tubes.

The inspection findings discussed above suggest that steam generator tubes remain susceptible to stress corrosion cracking (SCC) even after they have been plugged. Although the susceptibility to SCC of plugged tubes should be less than that for tubes remaining in service, many of the factors associated with the development of SCC remain unchanged (e.g., material susceptibility). The consequences of continued degradation of plugged tubes include the potential for complete severance of the tube and the potential for creation of loose parts, both of which could damage inservice tubes. Some utilities have installed tube stabilizers in tubes with outside-diameter-initiated circumferential defects before plugging them, which may lessen the potential to damage inservice tubes.

Discussion

As PWRs continue to age, new modes of steam generator degradation continue to appear. Historically, verification of tube integrity has focused on degradation which directly affected the tubes. However, the recent findings at Shearon Harris and San Onofre illustrate the importance of considering the impact of other modes of degradation on the integrity of steam generator tubes. Although inspection practices generally focus on locations in steam generator tubes where degradation has previously been identified, the examples presented here demonstrate that degradation taking place elsewhere in steam generators could potentially challenge the integrity of the tubes.

Because of improved inspection capability, specifically improvements in probes and data analysis software, earlier detection and perhaps more accurate sizing of tube degradation is possible. However, problems with tube inspections continue to occur. As discussed, these problems may arise from inadequate qualification of data analysis procedures or from errors associated with the acquisition of inspection data. It remains important for licensees to assess the significance of indications with respect to the qualification of the inspection techniques and the manner in which the indications were detected. Such practice is consistent with regulatory requirements in Criteria IX and XVI of Appendix B to 10 CFR Part 50. The conclusions from these assessments may dictate revisions to inspection procedures and repair of tubes.

This information notice requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

signed by

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