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Recent Operating Experience Related to Degradation of Passive Components at United States Nuclear Power Plants

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ABSTRACT

The Office of Nuclear Reactor Regulation, Division of Regulatory Improvement Programs, Operating Experience Section (OES) of the United States Nuclear Regulatory Commission reviews all reportable events from nuclear power plants (US NPPs) in the United States. The OES also coordinates all of the NRC's generic communications related to these events. Among the recent operating events that may be of interest to the international community, a few have involved degradation of passive components within the reactor coolant pressure boundary. This paper summarizes the information notices (INs) the NRC published from late 2000 through early 2002 with regard to these recent operating events.

Key Words:

nuclear power plant, operating experience, degradation, corrosion, reactor vessel head, steam generator tubes, reactor vessel internals, control rod drive mechanism penetration nozzles, stress corrosion cracking, boric acid corrosion, resonance frequency, erosion corrosion, intergranular attack

INTRODUCTION

Degradation of passive components within the reactor coolant pressure boundary continues to challenge some US NPPs. The NRC and its licensees recognize that operating experience is an important means of understanding these problems and preventing them from occurring at other nuclear facilities. Consequently, the operating experiences of US NPPS are documented in various sources, including the NRC's generic communications, licensee event reports, significant event reports prepared by the International Nuclear Power Organization (INPO), and publications from the International Atomic Energy Agency (IAEA). The NRC's generic communications include generic letters (GLs), bulletins (BLs), regulatory information summaries (RISs) and information notices (INs). Among these generic communications, the NRC publishes INs to disseminate information concerning significant events and lessons learned. This paper summarizes the INs that the NRC published from late 2000 through early 2002, as they relate to recent operating experience involving degradation of passive components within the reactor coolant pressure boundary.

INFORMATION NOTICE SUMMARIES

The following subsection summarize 10 INs related to degradation of passive components within the reactor coolant pressure boundary from late 2000 to early 2002.

IN 2003-02: Recent Experience with Reactor Coolant System Leakage and Boric Acid Corrosion

On December 26, 2002, Sequoyah Unit 2 tripped from full power as a result of low reactor coolant system (RCS) flow attributable to a ground fault in a reactor coolant pump motor winding. In the ensuing shutdown to correct the pump problem, the licensee initiated a search to locate and correct a suspected RCS leak that occurred before the reactor trip and resulted in elevated moisture and activity levels inside containment. During this inspection, the licensee identified an accumulation of boric acid on the reactor pressure vessel (RPV) head insulation, which resulted from a leaking reactor vessel level indication system (RVLIS) compression fitting. The leakage had seeped through a seam in the insulation onto the RPV head and resulted in minor boric acid corrosion of the head. This RVLIS compression fitting had been disconnected and reconnected during the May 2002 refueling outage. The licensee also identified a small leak through a canopy seal weld on an empty control rod drive mechanism (CRDM) penetration; however that leak did not result in any boric acid corrosion of the RPV head.

Based on the location of the leaking RVLIS fitting, the temperature of the leakage fluid was close to the ambient temperature outside the vessel insulation. The insulation had a seam in this area. The licensee estimated that the boric acid crystals on this insulation surface had a total mass of about 9 kilograms (20 pounds). On removing the insulation and cleaning the area, the licensee observed boric acid corrosion of the RPV head near the flange. The licensee determined that the amount of material loss from the head was small, in the shape of a groove less than 1 centimeter (cm) [0.3 inch] wide, about 12 cm [4.6 inches] long, and at most about 0.33 cm [0.125 inch] deep. The licensee=s evaluation indicated that 98 percent or more of the structural wall remained intact and no abrupt corners existed in the degraded area.

Historically, a number of mechanical and welded connections above the RPV head have leaked at a number of plants. This leakage of borated water may result in boric acid corrosion that may, in turn, lead to degradation of the low-alloy steel RPV head. At Sequoyah Unit 2, the leakage resulted in relatively minor degradation of the RPV head. In that event, the unidentified reactor coolant leakage had not shown a discernible increase from the very low levels that typically occur at a pressurized water reactor (PWR) facility. Common assumptions that RCS leakage onto a hot surface, such as the reactor pressure vessel head, will not cause corrosion may not be justified and are the subject of ongoing research. Usually, small quantities of water coming into contact with a surface as hot as the RPV head would be expected to flash and leave a noncorrosive dry boric acid residue on the surface. However, at Sequoyah Unit 2 the resulting condition produced an environment in which boric acid corrosion could occur. This experience challenges the current assumptions with respect to the potential effects of RCS leakage. The NRC is continuing to consider the safety and regulatory aspects of this experience.

IN 2002-26: Failure of Steam Dryer Cover Plate after a Recent Power Uprate

In March 2002, Quad Cities Unit 2, a boiling water reactor (BWR), completed a refueling outage that included a modification to add baffle plates to the steam dryer to reduce the excessive moisture carryover expected as a result of an extended power uprate (17.8% increase) from 2,511 MWt to 2,957 MWt. On June 7, 2002, the unit began experiencing fluctuations in steam flow, reactor pressure and level, and moisture carryover in the main steam lines. After additional fluctuations in June and July, the licensee conducted an engineering evaluation of one of the fluctuations and determined that the steam flow irregularities could be caused by loose parts in the steam line, which could impair the proper functioning of safety systems.

The licensee concluded that the steam dryer cover plate had failed. A scale model test conducted by General Electric attributed the failure to high cycle fatigue. On the basis of the test results, the licensee concluded that the fatigue resulted from excessive vibration caused by the synchronization of the cover plate resonance frequency, the nozzle chamber standing acoustic wave frequency, and the vortex shedding frequency. Each of these frequencies depends on the construction and geometry of the dryer, but the vortex shedding frequency also depends on the flow rate of the steam passing through the dryer area. The licensee concluded that the three frequencies synchronized in a very narrow band of steam flow at or near the steam flow required to reach full power under the power uprate conditions.

IN 2002-21: Axial Outside-Diameter Cracking Affecting Thermally Treated Alloy 600 Steam Generator Tubing

During an outage at Seabrook in May 2002, the licensee conducted inspections of the plant’s steam generator tubes, which were manufactured using thermally treated Alloy 600. While performing bobbin probe inspections of the tubes in Steam Generator D, the licensee detected indications of flaws at a number of tube- to-tube support plate intersections. Subsequent PlusPoint probe inspections confirmed the presence of axially oriented linear indications, initiating on the outside-diameter (OD) tube surface. The licensee also performed ultrasonic testing (UT), which further confirmed the findings. The licensee classified these indications as axial OD cracking.

Most steam generators placed into service before the early 1980s used tubing fabricated from mill-annealed Alloy 600 including replacement steam generators. This tubing was found to be susceptible to degradation, including stress corrosion cracking. Over time, such degradation became extensive and led to steam generator replacement at more than 30 units to date in the United States. The safety significance is that if licensees do not monitor, repair, and manage tube degradation appropriately, it may lead to primary-to-secondary leakage and/or a tube rupture.

To reduce susceptibility to stress corrosion cracking, many steam generators placed into service during the 1980s were made of thermally treated Alloy 600 tubing including replacement steam generators. Operating experience has confirmed the superior corrosion resistance of thermally treated Alloy 600 tubing. In fact, until the recent findings at Seabrook, no known or likely instances of stress corrosion cracking affecting thermally treated Alloy 600 tubing had been reported in the United States. The Seabrook findings underscore the importance of being alert during inspections to evidence of possible stress corrosion cracking, regardless of how long the steam generators have been operating.

IN 2002-13: Possible Indicators of Ongoing Reactor Pressure Vessel Head Degradation

This IN alerted licensees to possible indicators of reactor coolant pressure boundary degradation, including degradation of the reactor pressure vessel (RPV) head material. These indicators include unidentified reactor coolant system (RCS) leakage and containment air cooler (CAC) and radiation element (RE) filter fouling experienced at Davis-Besse Nuclear Power Station prior to the degradation of the RPV head (see the summary of IN 2002-11, below).

IN 2002-11: Recent Experience with Degradation of Reactor Pressure Vessel Head

On February 16, 2002, the Davis-Besse Nuclear Power Station in Oak Harbor, Ohio, began a refueling outage that included inspecting the nozzles entering the head of the reactor pressure vessel (RPV), the specially designed container that houses the reactor core and the control rods that regulate the power output of the reactor. A wastage area was found to extend approximately 12.7 cm (5 inches) downhill on the RPV head from the penetration for CRDM nozzle 3 and was approximately 10.2 to 12.7 cm (4 to 5 inches) at its widest part. The minimum remaining thickness of the RPV head in the wastage area was found to be approximately .95 cm (.375 inch). This thickness was attributed to the thickness of the stainless steel cladding on the inside surface of the RPV head, which is nominally .95 cm (.375 inch) thick.

The investigation of the causative conditions surrounding the degradation of the RPV head at Davis-Besse is continuing. Boric acid or other contaminants could be contributing factors. Other factors contributing to the degradation might include the environment of the RPV head (e.g., wet/dry) during both operating and shutdown conditions, the duration for which the RPV head is exposed to boric acid, and the source of the boric acid (e.g., leakage from the CRDM nozzle or from sources above the RPV head such as CRDM flanges). Extensive details and lessons learned about this event are provided on the NRC’s public website home page at www.nrc.gov.

IN 2002-02, Supplement 1: Recent Experience with Plugged Steam Generator

On March 25, 2002, Oconee Nuclear Station Unit 1 (ONS-1) was shut down for a refueling outage. In addition to the standard steam generator tube inspections, the licensee performed supplemental inspections of plugged tubes in both steam generators. These supplemental inspections were performed to address the plugged tube severance event at Three Mile Island Unit 1 (TMI-1), which is discussed in IN 2002-02, as summarized below. As a result of these inspections, the licensee identified a plugged tube at ONS-1 that had severed.

The licensee determined that the most likely cause of failure was inside diameter intergranular attack (IGA), which implies a corrosive environment inside the tube. This tube had a unique history, in that it was 1 of 12 tubes that had first-of-a-kind (FOAK) instrumentation installed in 1971 before the plant commenced commercial operation. The purpose of this instrumentation was to determine various temperature distributions in the once-through steam generator design. To conduct this testing, thermocouples were installed in 12 tubes in Steam Generator B. In accordance with the FOAK instrumentation installation procedure, the tube that would eventually sever was plugged with an explosive plug in the lower tubesheet in 1971. Testing was completed during the first cycle of operation in 1974, and an explosive plug was installed in the upper tubesheet at that time. It is likely the tube was approximately 50 percent full of water when the upper plug was installed. The upper tubesheet plug was backed up by a welded plug in 1993 as a result of concerns related to degradation of upper tubesheet explosive plugs.

Based on a number of observations and hypotheses, the licensee believes that the unique conditions of operation associated with the FOAK instrumentation are a primary contributor to the corrosive environment and eventual tube failure. The secondary-side flow conditions at the lower tubesheet are in the radial direction toward the center of the tube bundle. The licensee=s analysis of the flow conditions shows that velocities around the severed tube are large and would develop forces sufficient to pin the severed end of a tube against the adjacent tubes and cause wear.

The event at ONS-1 is another example of the potential for a plugged tube to affect the integrity of adjacent tubes. Although this phenomenon does not appear to be widespread, it may become more frequent as more tubes are plugged and as the plugged tubes remaining are in service for longer periods of time. Isolated occurrences of this phenomenon may be risk-significant.

IN 2002-02: Recent Experience with Plugged Steam Generator Tubes

While inspecting the tubes in Steam Generator B at TMI-1 during the fall 2001 refueling outage, the licensee identified signs of wear near the upper tubesheet on the outer surface of four tubes on the periphery of the tube bundle.

As a result of related inspection findings at the plant, the licensee identified two plugged tubes that had severed circumferentially. The NRC issued IN 2002-02, "Recent Experience with Plugged Steam Generator Tubes," to alert licensees to the potential severance of plugged steam generator tubes. In that IN, the Staff reported that a plugged tube, located on the periphery of the tube bundle at TMI-1, severed near the secondary side of the upper tubesheet and damaged four adjacent inservice (i.e., nonplugged) tubes. The preliminary laboratory investigation of the severed tube revealed signs of high cycle fatigue, ductile failure, and OD-initiated IGA. In addition, the tube diameter was greater than the nominal tube diameter, indicating that the severed tube had swollen. The licensee determined that the failure was most likely caused by fatigue attributed to flow-induced vibration of the swollen and restrained tube. The licensee further attributed the swelling to water leaking into the tube around the plugs while the unit was shut down. As the tube heated during plant startup, the water in the tube expanded faster than it could escape past the tube plugs, thereby resulting in a pressure buildup and subsequent swelling of the tube. The effect is called the "diode effect." The swelling, in turn, caused the tube to become clamped at the drilled hole in the fifteenth tube support plate and at the upper tubesheet. Under the high-flow conditions that existed in the area of the upper tubesheet, this clamping made the restrained tube more susceptible to fatigue caused by flow-induced vibration. The licensee also concluded that the IGA on the outside of the tube might have made it more susceptible to severing and that the plug type was probably a factor in the diode effect. The other plugged tube was circumferentially severed at the 15^{th} tube support plate, but the severed tube was caught within the tube support plate and didn't impact adjacent tubes. In addition, the industry concluded that it was unlikely that the once-through steam generator tubes would sever in the lower tubesheet region. The staff asked the industry to evaluate the generic implication of this occurrence.

IN 2001-16: Recent Foreign and Domestic Experience with Degradation of Steam Generator Tubes and Internals

During a steam generator secondary-side visual inspection in 1999, Baltimore Gas and Electric Company (BGE) identified degradation at the periphery of the eggcrate tube supports in both steam generators at Calvert Cliffs Nuclear Power Plant Unit 2. In Steam Generator 21, BGE identified minor degradation of the eggcrate supports on the hot-leg side at the sixth, seventh, and eighth support elevations. In addition, in Steam Generator 22, BGE identified more extensive degradation of the eggcrate supports on the hot-leg side at the seventh and eighth support elevations, as well as on the cold-leg side at the sixth support elevation. On the basis of the locations and nature of the degradation, BGE concluded that it was caused by erosion-corrosion, that was similar to, but much less extensive than, that observed at San Onofre Nuclear Generating Station Unit 3. The San Onofre experience is discussed in GL 97-06. BGE had performed similar secondary-side inspections at Calvert Cliffs Unit 1 in 1996 and 1998 and found no eggcrate degradation. BGE performed an upper bundle flush and sludge lancing of the steam generators during the 1999 inspection outage and adjusted chemistry levels to improve resistance to erosion-corrosion over the subsequent operating cycle.

The degradation of the Calvert Cliffs Unit 2 eggcrate supports illustrates the importance of monitoring secondary side structures and components that may impact tube integrity. If support structures (such as eggcrate supports) are permitted to degrade excessively, tube damage may occur as a result of the loss of support to the tube (i.e., tube vibration) and/or mechanical damage caused by the introduction of loose material into the steam generator. In the case of Calvert Cliffs, the degradation was not that severe, and the licensee was monitoring the support locations because an earlier analysis of the plant had indicated that it is one of the most susceptible to eggcrate tube support degradation based on feedwater iron transport rates. With respect to the long-term integrity of these steams generators, the licensee plans to install replacement steam generators at Calvert Cliffs Unit 1 in Spring 2002 and at Calvert Cliffs Unit 2 in Spring 2003. The replacement steam generators have stainless steel tube supports that are more resistant to erosion-corrosion.

IN 2001-16 also alerted licensees to a related condition at Turkey Point. The steam generators at Turkey Point Units 3 and 4 were replaced in 1982 and 1983, respectively, with steam generators of an improved design. The tubes of the replacement steam generators were made of a more corrosion-resistant material, thermally treated Alloy 600, and were hydraulically expanded and, therefore, subject to less residual stress. The quatrefoil tube supports were also more resistant to corrosion, being made of stainless steel.

During a steam generator tube examination in the spring of 2000, the licensee for Turkey Point Unit 3 detected 69 tubes that required plugging. Of those 69 plugged tubes, 41 had volumetric pit-like indications, 15 had inside-diameter-initiated circumferential indications, 8 had OD-initiated circumferential indications, and 5 had wear indications. Most of these indications were in the hot-leg hydraulic-expansion transition region at the top of the tube sheet. The volumetric and circumferential indications were detected with rotating probes. This was the first time rotating probes were extensively used at Turkey Point Unit 3.

The experience at Turkey Point illustrates the importance of performing comprehensive inspections of steam generator tubes throughout the lifetime of a steam generator regardless of the tube material. The thermally treated Alloy 600 steam generator tubes at Turkey Point are less susceptible to corrosion than mill-annealed Alloy 600 tubes. Nonetheless, the tubes are susceptible to degradation. In the case of Turkey Point Unit 3, the licensee postulated that the circumferential and volumetric eddy current signals could be attributable to manufacturing anomalies similar to those observed in pulled tubes removed from Surry and other locations. Without comprehensive inspections early in the life of a steam generator or without metallurgical examination of pulled tubes, evaluations to determine the cause of "new indications" are difficult to perform and subject to significant judgment. Since the likelihood of tube corrosion increases as steam generators age, it is important for licensees to conduct comprehensive special inspection processes and root cause evaluations.

IN 2001-05: Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3.

On February 18, 2001, Duke Energy Corporation performed a visual examination (VT-2) of the outer surface of the Oconee Nuclear Station, Unit 3's RPV head to identify any indications of borated water leakage. This RPV head inspection was performed as part of a normal surveillance during a planned maintenance outage. The VT-2 revealed the presence of small amounts of boric acid residue in the vicinity of 9 of the 69 CRDM penetration nozzles. Subsequent nondestructive examinations (NDEs) identified 47 recordable crack indications in these 9 degraded CRDM penetration nozzles. The licensee initially characterized these flaws as either axial or below-the-weld circumferential indications, and initiated repairs of the degraded areas. The licensee conducted NDEs of nine additional CRDM penetration nozzles from the same heat of material to determine the "extent of condition," but did not detect any recordable indications.

While implementing repairs of these nozzles, the licensee identified two nozzles with circumferential cracks. These cracks extended 165 degrees around the circumference and were through-wall. Subsequent re-analysis of the NDE data revealed an additional crack in one of these nozzles.

The NRC staff noted concerns about potential circumferential cracking (which would need to be addressed on a plant-specific basis), high residual stresses from initial manufacture and from tube straightening (sometimes done after welding), and the need for enhanced leakage monitoring.

The identification of significant circumferential cracking of two CRDM nozzles at ONS-3 raised concerns about a potentially risk-significant generic condition affecting all domestic PWRs. RPV head penetrations, including CRDM nozzles, maintain the reactor coolant system (RCS) pressure boundary and therefore, cracking of CRDM nozzles and welds degrades the primary RCS boundary. Industry experience has shown that Alloy 600 is susceptible to stress corrosion cracking (SCC). Further, the environment in the CRDM housing annulus will likely be far more aggressive after any through-wall leakage, because potentially highly concentrated borated primary water will become oxygenated, thereby increasing crack growth rates. Consequently, the NRC issued Bulletin 2001-01 in August 2001 to request information on licensee plans to perform inspections to address these concerns. Subsequently, the NRC has issued two additional bulletins, 2002-1 (issued March 2002) and 2002-02 (issued August 2002), and Order EA-03-009 (issued February 2003) to require specific inspections of RPV head and vessel head penetration nozzles.

IN 2000-17 and Supplement 1: Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V.C. Summer

On October 7, 2000, during a containment inspection after V.C. Summer entered a refueling outage, the licensee identified a large quantity of boron on the floor and protruding from the air boot around the "A" loop RCS hot leg pipe. The licensee performed a liquid penetrant test (PT) on October 12, 2000, which indicated the existence of a 10.2-cm (4-inch) long circumferential indication in the first weld between the reactor vessel nozzle and the "A" loop hot-leg piping, approximately 0.91 meter (3 feet) from the RPV.

Ultrasonic and eddy current testing also identified an axial crack-like indication at a different location. This indication is approximately 6.9 cm (2.7 inches) long, and is located approximately 9 degrees counterclockwise from top dead center (TDC) of the weld. Based on the UT data, the axial crack-like indication begins at the inside diameter and shows evidence of complete through-wall extension. Visual examination from the OD identified a small "weep hole" in the center of the weld at approximately the same circumferential location as the UT and eddy current indications. A PT of this area could not confirm the existence of the axial crack-like indication on the OD because of slight leakage from the "weep hole." The UT and eddy current testing show that the crack-like indication extends from approximately the centerline of the weld toward the reactor nozzle.

LESSONS LEARNED

Examination of these events yields the following lessons learned:

- Resonance frequency in uprates may cause degradation as a result of high cycle fatigue.
- It is important to monitor secondary side components that may affect steam generator tube integrity.
- A plugged steam generator tube has the potential to sever and affect the surrounding tubes.
- Regardless of steam generator design or materials, it is important to effectively monitor the tubes and their support structures to ensure that tube structural and leakage integrity are maintained.
- Improved inspection techniques may be more sensitive to identifying degradation.
- The environment in the CRDM housing annulus will likely be far more aggressive after any through-wall leakage.
- There may be several available indicators of degradation other than direct inspection. These may include increased moisture inside containment, unidentified RCS leakage, and containment air cooler and radiation filter fouling.
- Corrosion rates may be significantly underestimated for identified boric acid leaks because of erroneous assumptions regarding the nature of the leakage, environmental conditions, the relationship between the actual leakage and experimental data, or other factors.
- Fixing problems should be priority rather than a "workaround."

Information and lessons learned about the Davis-Besse Reactor Head are quite extensive. Details about these lessons learned may be found on the NRC's Website at www.nrc.gov, which provides several pointers to information about various aspects and lessons learned about the Davis-Besse event. The Web site also provides access to the complete text of the INs summarized above.

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