ATTACHMENT 71111.08

INSPECTABLE AREA: Inservice Inspection Activities

CORNERSTONES: Initiating Events (45%)
Barrier Integrity (45%)
Mitigating Systems (10%)

INSPECTION BASES: Inservice inspection (ISI) activities can detect precursors to pressure boundary failures in reactor coolant systems (RCS), emergency core cooling systems (ECCS), risk-significant piping and components, and containment systems. Degradation of pressure boundaries of reactor coolant systems, steam generator tubes, emergency feedwater systems, essential service water systems, and containments would result in a significant increase in risk. This inspection is intended to assess the effectiveness of the licensee's program for monitoring degradation of vital system boundaries.

The scope of this inspectable area is limited to the following structures, systems, and components (SSCs):

a. Reactor coolant system pressure boundaries, including steam generator tubes in pressurized water reactors (PWRs).

b. Piping connected to the RCS, failure of which could result in an interfacing system loss of coolant accident.

c. Reactor vessel internals.

d. Risk-significant piping system boundaries.

e. Containment system boundaries (including coatings and post-tensioning systems, where applicable).

LEVEL OF EFFORT: Inspections are generally to be performed during each refueling outage at each reactor unit at a site. The level of ISI activities including steam generator inspections at each plant can vary significantly from outage to outage but typically should be as identified in this procedure.

71111.08-01 INSPECTION OBJECTIVE

To assess the effectiveness of the licensee's program for monitoring degradation of the reactor coolant system boundary, risk-significant piping system boundaries, and the containment boundary.

71111.08-02 INSPECTION REQUIREMENTS

02.01 <u>Inspection Activities Other Than Steam Generator Tube Inspections, PWR Vessel Upper Head Penetration Inspections, Boric Acid Corrosion Control</u>

a. Review a sample of nondestructive examination (NDE) activities. The review sample should consist of two or three types of NDE activities:
   (a) Volumetric examinations
   (b) Surface examinations
   (c) Visual examinations

b. For each NDE activity reviewed, perform the following through either direct observation (preferred method) or record review:

   1. Verify that the activities are performed in accordance with ASME Boiler and Pressure Vessel Code requirements.

   2. Verify that indications and defects, if present, are dispositioned in accordance with the ASME Code or an NRC approved alternative (e.g., approved relief request).

c. Review one or two examinations with recordable indications that have been accepted by the licensee for continued service. Verify that the licensee's acceptance for continued service was in accordance with the ASME Code or an NRC approved alternative.

d. If welding on the pressure boundary for Class 1 or 2 systems has been completed, verify for one to three welds that the welding process and welding examinations were performed in accordance with ASME Code requirements or an NRC approved alternative.

02.02 <u>PWR Vessel Upper Head Penetration (VUHP) Inspection Activities</u> ***(To be implemented after the completion of TI 2515/150)***

The inspection requirement steps in 02.02 parallel the inspection requirement steps in 02.01. The inspection of the licensee's reactor VUHP activities under 02.02.a and b may be considered as satisfying the corresponding inspection requirements of 02.01.a and b.

a. If the licensee is performing visual examinations, observe portions of this examination or review the post examination videotape and examination procedures. In particular, review licensee criteria for confirming visual examination quality and instructions resolving interference or masking issues.

   And/or;

   If the licensee is performing non-visual nondestructive examination (NDE) of the reactor vessel head, review a sample of these examinations. In particular, review the NDE examination procedures used to confirm that they are consistent with ASME Code examinations or that the equipment and calibration requirements (essential variables) are consistent with that used in vendor mockup demonstrations on simulated or actual cracking.

   And

   Review the records recording the extent of inspection for each penetration nozzle including documents which resolved interference or masking issues.

b. For each NDE activity reviewed, perform the following through either direct observation (preferred method) or record review:

1. Verify that the activities are performed in accordance with the requirements of NRC Order EA-03-009.

2. Verify that indications and defects, if detected, were dispositioned in accordance with the ASME Code or an NRC approved alternative (e.g., approved relief request).

c. Review one or two examinations with recordable indications that have been accepted by the licensee for continued serviced. Verify that the licensee's acceptance for continued service was in accordance with the ASME Code or an NRC approved alternative.

d. If welding repairs have been completed on upper head penetrations, verify for one to three welds that the welding process and welding examinations were performed in accordance with ASME Code requirements or an NRC approved alternative.

02.03 Boric Acid Corrosion Control (BACC) Inspection Activities (PWRs)

a. Review a sample of BACC walkdown visual examination activities through either direct observation (preferred method) or record review.

b. Verify that visual inspections emphasize locations where boric acid leaks can cause degradation of safety significant components.

c. Review one to three engineering evaluations performed for boric acid found on RCS piping and components. Verify that engineering evaluations of degradation by boric acid ensured that ASME Code wall thickness requirements are maintained. Also, verify that degraded or non-conforming conditions are identified properly in licensee's corrective action system.

d. Review one to three corrective actions performed for evidence of boric acid leaks identified. Confirm that these corrective actions were consistent with requirements of the ASME Code and 10CFR50 Appendix B Criterion XVI.

02.04 Steam Generator (SG) Tube Inspection Activities

a. In-situ Pressure Testing.

1. Assess whether the in-situ screening criteria are in accordance with the EPRI Guidelines. In particular, assess whether assumed NDE flaw sizing accuracy is consistent with data from the EPRI examination technique specification sheet (ETSS) or other applicable performance demonstrations.

2. In conjunction with step 02.04a.1, assess whether the appropriate tubes are to be In-situ pressure tested (in terms of specific tubes and number of tubes according to the screening criteria).

3. Review plans for and, if practical, observe in-situ pressure testing activities and assess whether tubes are in-situ tested in accordance with EPRI In-situ Pressure Test Guidelines. Assess test records (e.g., pressure versus time traces, pressure achieved, and hold times).

4. Review in-situ pressure test results for conformance with the performance criteria.

b. Compare the estimated size and number of tube flaws detected during the current outage against the previous outage operational assessment predictions to assess the licensee's prediction capability.

c. Confirm that the SG tube eddy current examination (ECT) scope and expansion criteria meet technical specification (TS) requirements, EPRI Guidelines, and commitments made to the NRC .

d. If the licensee has identified new degradation mechanisms, verify that the licensee has fully enveloped the problem in its analysis of extended conditions including operating concerns, and has taken appropriate corrective actions before plant startup (e.g., additional inspections, in-situ pressure testing, preventive tube plugging, etc.).

e. Confirm that all areas of potential degradation (based on site-specific experience and industry experience) are being inspected, especially areas which are known to represent potential ECT challenges (e.g. top-of-tubesheet, tube support plates, U-bends).

f. Confirm that all repair processes being used have been approved in the technical specifications for use at the site.

g. Repair Criteria.

    1. Confirm that the TS plugging limit is being adhered to, unless alternate tube repair techniques (e.g., sleeving or alternate repair criteria) have been approved by the NRC. Typically, the TS plugging limit is 40 percent through wall, although most licensees "plug on detection" due to the unavailability of qualified depth sizing techniques.

    2. Determine whether the depth sizing repair criterion (typically 40 percent through wall) is being applied for indications other than wear or axial primary water stress corrosion cracking (PWSCC) in dented tube support plate intersections.

h. If steam generator leakage greater than 3 gallons per day was identified during operations or during post-shutdown visual inspections of the tubesheet face, assess whether the licensee has identified a reasonable cause for this leakage based on inspection results. In addition, determine whether corrective actions are planned or were taken to address the cause. Additional guidance on this issue is available in Part 9900: Technical Guidance, "Steam Generator Tube Primary-to-Secondary Leakage."

i. Confirm that the ECT probes and equipment are qualified for the expected types of tube degradation. Assess the site specific qualification of one or more techniques (e.g., equipment, data quality/noise issues, degradation mode).

j. If the licensee has identified loose parts or foreign material on the secondary side of the steam generator, focus on licensee corrective actions in conjunction with step 02.05 below. Specifically, confirm that the licensee has taken/planned appropriate repairs of affected SG tubes, inspected the secondary side of the SG to remove foreign objects (if possible). If the foreign objects are inaccessible, determine whether the licensee has performed an evaluation of the potential effects of object migration and/or tube fretting damage.

k. If serious questions arise regarding eddy current data analyses from steps 02.04a., d., or i., review one to five samples of eddy current data. If adequate expertise for this activity does not reside in the regional office, NRR/DE should be contacted via telephone call or e-mail and it will provide this resource.

02.05 Identification and Resolution of Problems. Verify that the licensee is identifying ISI/SG problems at an appropriate threshold and entering them in the corrective action program. Determine whether the licensee's procedures direct the licensee to perform a root cause evaluation and take corrective actions when appropriate. For a selected sample of problems associated with inservice inspection and steam generator inspection documented by the licensee, verify the appropriateness of the corrective actions. See Inspection Procedure 71152, "Identification and Resolution of Problems," for additional guidance. In addition, a licensee's evaluation of industry operating experience can be critical. Determine whether licensees are assessing the applicability of operating experience to their respective plants.

71111.08-03 INSPECTION GUIDANCE

General Guidance

Cornerstones	Inspection Objective	Risk Priority	Examples
Initiating Events or Barrier Integrity or Mitigating Systems	Verify the effectiveness of programs for monitoring the conditions of: 1) the RCS pressure boundary and containment barriers, 2) the boundaries of risk-significant components in auxiliary and ECCS piping systems	Reactor vessel Steam generator tubes Vessel penetrations ASME Class 1 piping ECCS connections to the RCS Auxiliary feedwater system piping Essential service water system piping Other risk-significant piping components Steel containment vessel Post-tensioning systems and steel liner for Concrete containment Shutdown and spent fuel cooling system pressure boundaries	Reactor vessel and vessel penetration examination Steam generator tube eddy current testing Visual, volumetric or surface examinations of risk-significant piping components Inspection and testing of containment post-tensioning systems

For PWRs, the effort expended and the level of detail considered in performing these activities will be determined on the basis of review of the previous inspection results summary report required by Technical Specifications, findings from the previous NRC inspection, and interaction with NRR/DE/EMCB staff with some possible edification for observations made during the upcoming inspection. Each region shall during its annual inspection planning determine for the total inspection effort where to place the emphasis in regard to non-SG ISI activities (Sections 02.01 through 02.03) and SG inspection activities within the estimated resources. Also, note, when applying the requirements of 02.01 through 02.03, if timing does not permit an inspection step to be performed on an activity occurring in the current outage, the step may utilize the activity performed during the previous outage. In other words, these samples may be chosen from current or previous outage.

Specific Guidance

03.01 Inspection Activities Covered By Section 02.01 No specific guidance.

03.02 Inspection Activities Covered By Section 02.02 As part of the preparation for vessel upper head inspection, the inspector should consider reviewing NRC Bulletins 2001-01, Bulletin 2002-01, Bulletin 2002-02 and NRC first revised Order EA-03-009. The inspector should review the licensee responses to the order, requests for relaxation from the order and any NRC approved relaxations from the order.

03.03 Inspection Activities Covered By Section 02.03 As part of the preparation for inspection of boric acid corrosion control, the inspector should consider reviewing Generic Letter 88-05 and RIS 2003-13. The inspector should review licensee commitments made in response to this generic letter. Appendix B provides a list of typical PWR plant systems containing boric acid.

03.04 Steam Generator (SG) Tube Inspection Activities. The inspection should be scheduled towards the end of the SG inspection activities, if possible, because the licensee performs a significant number of evaluations (listed in 02.04) at that time.

Attachment A lists specific situations which, if identified by the inspector, require notification of NRR/DE staff. In addition, the inspector is encouraged to contact NRR/DE staff to discuss any other situations or issues that are identified, that are unexpected based on the inspector's experience.

As a part of the preparation for SG tube inspections, the inspector should consider reviewing the licensee's commitments in response to Generic Letters (GLs) 95-03, 95-05, 97-05, and 97-06 (see References Section 06). In addition, the inspector should review the licensee's most recent SG inspection summary report. The inspector should also consider reviewing NRC generic communications, such as relevant information notices and regulatory information summaries. Lastly, the inspector should become familiar with the industry steam generator program guidelines contained in Nuclear Energy Institute (NEI) 97-06 and several related Electric Power Research Institute (EPRI) reports (see References Section 06). The EPRI guidelines referenced do not constitute NRC requirements or commitments and technically acceptable alternative methods may be used by the licensee. Also, the staff has determined that while the guidelines represent an improvement over practices followed in the past, use of the guidelines alone does not ensure that the regulations will be satisfied. However, if the licensee has deviated from the guidelines, the basis for the deviation should be documented by the licensee.

Periodically, for plants that have SGs with active degradation or other SG issues, NRR/DE staff conduct a conference call with the licensee to discuss SG tube examination activities. If scheduled by NRR, the inspector should participate in the conference calls set up between NRC and licensee staff (as the timing of the call permits), during which steam generator tube examination activities are discussed. In addition, the inspector should review summaries from previous similar conference calls and can obtain these from NRR/DE staff. The information obtained during these calls will be beneficial to the inspector for background information as well as potentially providing direction for inspection activities.

Use the factors discussed below to determine the allocation of the inspection effort for review of the licensee SG inspection activities as described in 02.04. If none of these factors apply, the minimum inspection requirement is to complete steps 02.04a., c., d., g.(1), h., i., and j. If any of the factors apply, this baseline inspection effort should include the inspection of all SG activities identified in 02.04. If the safety significance of the operating experience warrants, then consider increasing the depth of the baseline SG inspection effort beyond the maximum estimated resources if recommended by NRR/DE/EMCB and approved by NRR/DIPM/IIPB.

1. SGs with mill-annealed or stress relieved Inconel Alloy 600 tubes should receive a review as described in this section at least every other outage, or more frequently if other factors discussed below apply. For SGs with thermally-treated Inconel Alloy 600 and thermally-treated Alloy 690 tubes this review may not be required unless considerable inservice time (>9 yrs since beginning commercial operation and more than 2 operating cycles since the last NRC inspection of the licensee's SG inspection activities) or other factors discussed below apply.

2. Deteriorating SG tube material condition as indicated by new degradation mechanism(s), or a large number or significant increase in the number of degraded or defective tubes reported by the licensee during the previous SG tube examinations. This information can be obtained from the licensee's most recent SG inspection summary report.

3. SG tube performance criteria (i.e., operational leakage, structural integrity, or accident leakage) were not met during the previous operating cycle.

4. PWRs with a history of primary-to-secondary leakage during the previous operating cycle (e.g. > 3 gallons per day).

5. Reported potential degraded condition (e.g. NRC and industry information notices) due to SG design, water chemistry, material properties, or newly identified degradation mechanisms.

03.04 a-f No specific guidance.

03.04.g.2. This criteria may be acceptable and in accordance with the licensee's TS, although experience has shown, for example, that many types of IGA/SCC cannot be sized with a sufficient degree of accuracy or reliability. In addition, this may indicate licensee practices that are inconsistent with their response to GL 97-05. If that is the case, contact NRR: DE.

03.04 h It is suggested that the NRC resident inspectors and regional staff use an informal screening criteria of 3 gpd or greater for increased involvement by NRC headquarters staff when steam generator primary to secondary leakage is identified. This is not meant to be an absolute threshold, or requirement, because there may be certain instances where there is something unusual about the circumstances of the leakage, or other reason that the region would want involvement by the headquarters staff before leakage reaches 3 gpd. If a licensee reports levels of primary-to-secondary leakage exceeding 3 gpd to the resident inspector or regional staff, Office of Nuclear Reactor Regulation (NRR) should be informed through the morning phone calls. The Materials and Chemical Engineering Branch (EMCB) staff is interested in being kept abreast of this information by NRR, Division of Licensing Project Management. EMCB staff would be concerned about the rate of change of the leakage, to assess how quickly the situation is changing. The following section discusses some of the typical questions that inspectors can pursue with the licensee when leakage is reported. EMCB staff is available if further direction is needed.

When leakage exceeds 3 gpd, parameters that can be considered are the effectiveness of licensee procedures, equipment, and practices for monitoring and responding to primary-to-secondary leakage. For example, the adequacy of procedures and equipment to provide real-time information on leak rate and its rate of change could be assessed. The appropriate setting of alarm setpoints on those radiation monitors that are used for detecting primary-to-secondary leakage (e.g., condenser air ejector, N-16) to alert operators to any increasing leak rate could be assessed. In addition, the adequacy of emergency operating procedures, availability of systems and components, and operator training for response to steam generator tube ruptures could also be assessed.

The NRR staff often receives notification of extremely low levels of leakage (<1 gpd), but these levels of leakage don't typically need to result in increased interaction with the licensee. This is because many plants have experienced this level of leakage during a full cycle, and it's difficult to definitively determine the source of the leakage at that level. Often, small levels of leakage will persist for the rest of the operating cycle for some plants.

03.04 i-k No specific guidance.

03.05 No specific guidance.

71111.08-04 RESOURCE ESTIMATE

This inspection procedure is estimated to take, on the average, 16 to 32 hours for each BWR unit, and 80 to 100 hours per PWR unit, respectively, every refueling outage.

Depending on availability, resident staff members may assist the regional ISI inspectors in completing section 02.03, Boric Acid Corrosion Control (BACC) Inspection Activities (PWRs).

71111.08-05 COMPLETION STATUS

Inspection of the minimum sample size will constitute completion of this procedure in the Reactor Program System (RPS). The minimum sample size for BWRs will consist of 1sample of the activities described in Section 02.01. The minimum sample size for PWRs will consist of 4 samples of activities described in Sections 02.01, 02.02, 02.03, and 02.04.

71111.08-06 REFERENCES

ASME Boiler and Pressure Vessel Code Sections III, V, IX, and XI.

Plant-specific ISI program.

GL 95-03, "Circumferential Cracking of Steam Generator Tubes,"

GL 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking."

GL 97-05, "Steam Generator Tube Inspection Techniques."

GL 97-06, "Degradation of steam Generator Internals."

NEI 97-06, “Steam Generator Program Guidelines.”

“PWR Steam Generator Examination Guidelines,” EPRI Report TR-107569.

“Steam Generator Integrity Assessment Guidelines,” EPRI Report TR-107621.

“Steam Generator In Situ Pressure Test Guidelines,” EPRI Report TR-107620.

Inspection Procedure 71152, “Identification and Resolution of Problems.”

Part 9900: Technical Guidance, “Steam Generator Tube Primary-to-Secondary Leakage.”

GL 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants.”

NRC Bulletin 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Pressure Boundary Integrity.”

First Revised Order, EA-03-009, “Issuance of Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors,” February 20, 2004.

RIS 2003-13, “NRC Review of Responses to Bulletin 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity.”“

NRC Bulletin 2003-02, “Leakage From Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity.”

WCAP-15988-NP, “Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors,” March 2003 (ADAMS Accession No.ML041190170).

END

APPENDIX A

Tube Integrity Issues Requiring Further Evaluation by NRR Staff

If the following situations are identified by the inspector, NRR/Division of Engineering (DE) staff should be promptly contacted. NRR/DE staff will determine whether NRR involvement is necessary. In addition, the inspector is encouraged to contact NRR/DE staff to discuss any other situations or issues that are identified, that are unexpected based on the inspector's experience.

1. Selection of tubes to be in-situ pressure tested is not consistent with EPRI guidance (i.e., number of tubes to be tested, or specific tubes to be tested, or NDE uncertainty is not consistent with data from the EPRI examination technique specification sheet (ETSS) or other applicable performance demonstrations).

2. In-situ pressure testing of flawed tubes is not successful in reaching the desired test pressure (e.g. main steam line break for accident induced leakage, 3 times normal operating differential pressure and 1.4 times main steam line break pressure for burst), either due to tube failure/leakage or equipment problems/limitations.

3. Estimated size or number of tube flaws detected during the current outage invalidates bounding assumptions from the previous outage operational assessment predictions.

4. If the licensee's use of depth sizing is inconsistent with their response to NRC Generic Letter 97-05.

5. A tube repair criteria or repair process is being used which has not been reviewed by the NRC for use at this site (e.g. alternate tube repair criteria, or sleeving process).

6. If tube inspections or testing do not identify the source of primary-to-secondary leakage observed during the previous operating cycle or during post-shutdown visual inspections of the tubesheet face.

APPENDIX B

Listing of PWR Systems Containing Boric Acid

1. Reactor Coolant Systems
2. Chemical and Volume Control System
3. Safety Injection System
4. Residual Heat Removal/Shutdown Cooling System
5. Reactor Plant Sampling System
6. Spent Fuel Pool Cooling and Purification System
7. Containment Depressurization System
8. Containment Spray System
9. Reactor Plant Vent and Drain System
10. Liquid Waste Disposal System
11. Gaseous Waste Disposal System