

NRC INSPECTION MANUAL

IRIB

INSPECTION PROCEDURE 71111 ATTACHMENT 08

INSERVICE INSPECTION ACTIVITIES

Effective Date: January 1, 2019

PROGRAM APPLICABILITY: IMC 2515A

CORNERSTONES: Initiating Events
Barrier Integrity
Mitigating Systems

INSPECTION BASES: See Inspection Manual Chapter (IMC) 0308, Attachment 2,
"Technical Basis for Inspection Program"

SAMPLE REQUIREMENTS:

Sample Requirements		Minimum Baseline Sample Completion Requirements		Budgeted Range	
Sample Type	Section(s)	Frequency	Sample Size	Samples	Hours
Boiling Water Reactor (BWR)	03.01a	Each refueling outage	1 per unit	1	36 +/- 6 per unit
Pressurized Water Reactor (PWR)	03.01a-d	Each refueling outage	1 per unit	1	90 +/- 10 per unit*

* Reduce the planned resources by approximately 20 hours when either reactor head (Section 03.01b) or steam generator (SG) (Section 03.01d) inspections do not apply and by 40 hours when both do not apply.

71111.08-01 INSPECTION OBJECTIVE

To verify that the reactor coolant system boundary, SG tubes, reactor vessel internals, risk-significant piping system boundaries, and containment boundary are appropriately monitored for degradation and that required repairs and replacements are appropriately examined and accepted.

71111.08-02 GENERAL GUIDANCE

Review the outage schedule and stay informed of any schedule changes. Coordinate inspection efforts with the licensee to ensure that inspection opportunities are not missed. Direct observation of nondestructive examination (NDE) activities is preferable to document review.

For inspection planning, consider relevant operating experience and interactions with the

U.S Nuclear Regulatory Commission (NRC) Office of Nuclear Reactor Regulation (NRR) to determine the emphasis of the inspection. Review the previous summary outage report that the licensee submitted to the NRC and review the NRC's ISI inspection results.

For Sections 03.01a through 03.01d, inspectors may select activities from a previous outage based on appropriate judgment or when timing does not allow for an inspection.

For this sample, conduct a routine review of problem identification and resolution activities using Inspection Procedure (IP) 71152, "Problem Identification and Resolution."

71111.08-03 INSPECTION SAMPLES

03.01 Inservice Inspection Activities Sample

- a. Nondestructive Examination and Welding Activities. This section applies to both BWRs and PWRs.

Verify that the licensee is conducting selected NDEs appropriately and addressing any identified defects appropriately.

Specific Guidance

1. Select at least one volumetric examination and one or more other types of NDEs on risk-significant welds or components to review.

The examination review selection preference, from most preferred to least preferred, is as follows:

- (a) volumetric examinations
- (b) surface examinations
- (c) visual examinations of the containment (as required by Subsections IWE and IWL of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code))
- (d) visual examinations

Volumetric examinations provide the greatest amount of information as compared to surface and visual examinations. Focus reviews on risk-significant welds or components, and recent NRC approved alternatives related to inservice inspection requirements.

2. For each examination reviewed, verify the following through either direct observation (preferred method) or record review:
 - (a) The following applies to examinations required by the ASME Code:
 - (1) NDE activities are performed in accordance with ASME Code requirements, as conditioned in Title 10 of the Code of Federal

Regulations (10 CFR) 50.55a.

- (2) Indications and defects, if present, are dispositioned in accordance with the ASME Code or an NRC-approved alternative (e.g., approved relief request).
 - (3) Relevant indications are compared to previous examinations to determine whether any changes have occurred.
- (b) The following applies to other augmented license renewal or industry initiative examinations:
- (1) Activities are performed in accordance with the licensee's augmented inspection program and associated examination procedure (e.g., examinations of components such as vessel internals subject to fatigue, intergranular stress corrosion, or irradiation-assisted stress corrosion; feedwater pipe subject to flow-accelerated corrosion; nickel-based weldments subject to primary water stress-corrosion cracking (SCC)).
 - (2) Indications and defects, if present, are dispositioned in accordance with the licensee's procedures and NRC requirements.
 - (3) Activities are performed in accordance with applicable industry guidance documents, aging management programs, and commitments.
3. If applicable, review at least one volumetric or surface examination from the previous outage with relevant indications that the licensee analytically evaluated and accepted for continued service. The licensee's acceptance needs to be in accordance with the ASME Code or an NRC-approved alternative. Confirm that any indications were examined for acceptability for continued service.
4. If applicable, for modifications, repairs, or replacements consisting of welding on pressure boundary risk-significant systems, review one or more welds to assure that the welding activities and any applicable NDE were performed in accordance with ASME Code requirements or an NRC-approved alternative.

Additional Specific Guidance

Inspections performed using IP 71003, "Post-Approval Site Inspection for License Renewal," may be credited under this IP.

When performing a review or observation of the containment general visual examination (Subsection IWE or Subsection IWL, or both, of Section XI of the ASME Code), ensure that the scope of the visual examination includes areas that are difficult to access (e.g., high dose areas or confined space areas such as under the vessel or sumps) or areas made visible by maintenance activities (e.g., weld test channels). Additionally, if the licensee has identified containment areas inaccessible for visual examination, review the basis for this determination and, if appropriate, conduct a historical review of previous containment visual examination records.

For nonrisk-based ISI programs, ASME Code, Section XI, Table IWX-2500-1,

identifies the required NDE method, frequency, extent, and acceptance criteria. ASME Code, Section V or Section XI, Mandatory Appendix I, III, or VIII further describes the specific NDE methods.

For risk-based ISI programs, the licensee's risk-based ISI program, which is typically based on Electric Power Research Institute (EPRI) Topical Report (TR)-112657, "Revised Risk-Informed Inservice Inspection Evaluation Procedure," Revision B-A, issued December 1999 (Agencywide Documents Access and Management System (ADAMS) Accession No. [ML013470102](#)), with ASME Code Case N-578-1 or Code Case N-716-1, identifies the required NDE method, frequency, extent, and acceptance criteria.

For BWR vessel internal inspections, EPRI TR-105696 (BWRVIP-03), "Reactor Pressure Vessel and Internals Examination Guidelines", identifies the NDE method, frequency, extent, and acceptance criteria. For any identified deviations with possible safety implications, the inspector should inform the applicable NRR branch.

For review of NDE records with recordable relevant indications, determine that the indications were properly characterized (ASME Code, Section XI, Article IWA-3300) and recorded (ASME Code, Section XI, Subsection IWA-3200) and appropriate acceptance criteria applied (ASME Code, Section XI, Subsection IWX-3000). If the flaw exceeds inservice acceptance criteria, determine whether the flaw was appropriately analyzed and accepted for continued service (ASME Code, Section XI, Article IWX-3130).

For review or observation of ASME Code, Section XI, welded repairs or replacements, do the following:

- Determine whether the weld procedure specification (WPS) contains the essential and supplemental essential weld variables (this only applies when the construction code (e.g., ASME Code, Section III, or U.S.A. Standard Code for Pressure Piping (USAS) B31.1) requires impact tests for the welding processes authorized by the WPS (ASME Code, Section IX, QW-200).
- Determine whether the WPS controls essential and supplemental essential weld variables within the ranges demonstrated and qualified by the supporting procedure qualification records (ASME Code, Section IX, QW-250).
- Observe available welding activities (or review weld records) to determine whether the appropriate base and weld filler materials are being used and that welding variables are controlled in accordance with the WPS.
- Review weld data records or observe postweld NDE, or both, to determine whether the construction code-required NDE methods and acceptance criteria (e.g., ASME Code, Section III, Section XI, or USAS B31.1) were applied for weld acceptance. If the inspector identifies concerns with the NDE procedures used to verify weld acceptance, confirm that these procedures are in accordance with the applicable construction code and ASME Code, Section V, requirements.

- b. Pressurized-Water Reactor Vessel Upper Head Penetration Inspection Activities. This section applies only to PWRs receiving vessel upper head penetration (VUHP) inspections during the refueling outage. Credit VUHP inspection activities performed

toward the completion inspection objectives under Section 03.01a for NDE, where applicable.

The periodic NRC inspections of PWR vessel head penetration nozzle and the reactor pressure vessel head area examinations below satisfy Davis-Besse Lesson Learned Task Force Recommendation No. 3.3.4.2(3). [C-1]

Verify that the licensee is conducting VUHP inspections appropriately and addressing any identified defects appropriately.

Specific Guidance

As part of the preparation for a VUHP inspection, consider reviewing NRC Bulletin (BL) 01-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," dated August 3, 2001; BL 02-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," dated March 18, 2002; BL 02-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," dated August 9, 2002; and NRC First Revised Order EA-03-009, "Issuance of Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," dated February 20, 2004. These documents provide the background behind 10 CFR 50.55a(g)(6)(ii)(D).

If the licensee is planning to perform a bare metal visual examination of the VUHPs before the onsite inspection, determine the type of records that the licensee intends to produce for the reactor head vessel head bare metal visual examination (e.g., videos, photos).

The NRC expects the inspector to directly observe portions of the visual examination or, at a minimum, review the video tape or photographic examination records. In the unlikely event that the inspector was not able to directly observe the examination and neither video nor photographic records exist, review the available examination records and discuss the examination results with the lead ISI staff or lead vendor examiner.

1. If the licensee is performing a bare metal visual examination of the VUHPs, review the examination procedure, and either observe portions of this examination (preferred method) or review the postexamination records. Licensee criteria for confirming visual examination quality and instructions for resolving interference or masking issues are contained in 10 CFR 50.55a(g)(6)(ii)(D).

And/or

If the licensee is performing a nonvisual NDE of the reactor vessel head, review a sample of these examinations. In particular, review the NDE examination results and procedures used to confirm that they meet ASME Code Case N-729-4. Confirm that the ultrasonic examination procedures and equipment used were qualified by a blind demonstration test in accordance with 10 CFR 50.55a(g)(6)(ii)(D).

And

Review the records documenting the extent of the inspection for each penetration nozzle, including documents that resolved interference or masking

issues to confirm that the extent of the examination meets the requirements in 10 CFR 50.55a(g)(6)(ii)(D). Specifically, do the following for the penetration locations reviewed:

- (a) For visual NDE, confirm that the coverage has been achieved and that limitations in coverage are properly recorded.

And/or

- (b) For nonvisual NDE, confirm that essentially 100 percent (i.e., greater than or equal to 90 percent) of the required examination volumes and surfaces were examined. Additionally, confirm that a volumetric (i.e., ultrasonic examination—backwall leakage pattern) or surface leakage path examination assessment (i.e., wetted J-groove weld surface eddy current or dye penetrant examination) was completed.
- 2. If relevant indications have been identified that were accepted for continued service, review a sample of the examination records and associated evaluations that accept these conditions. Verify that the licensee's acceptance for continued service was in accordance with 10 CFR 50.55a(g)(6)(ii)(D) or an NRC-approved alternative.
 - 3. If welding repairs have been completed on VUHPs, review a sample of these repairs. Verify that the welding process and welding examinations were performed in accordance with the requirements of the ASME Code and 10 CFR 50.55a(g)(6)(ii)(D) or an NRC-approved alternative.

- c. PWR Boric Acid Corrosion Control Inspection Activities. This section applies only to PWRs. The resident inspectors may assist the ISI inspectors in completing this section.

The periodic inspection of PWR plant boric acid corrosion control programs below satisfies Davis-Besse Lesson Learned Task Force Recommendation No. 3.3.2.2(1). [C-2]

Verify that the licensee is managing boric acid appropriately to guard against corrosion mechanisms that could lead to the degradation of safety-significant components.

Specific Guidance

- 1. Perform an independent review of plant areas that have recently received a boric acid walkdown by the licensee through either direct observation (preferred method) or record review. Visual inspections performed should emphasize locations where boric acid leaks can cause degradation of safety-significant components. Any degraded or nonconforming conditions should be entered into the licensee's corrective action program.
- 2. Review one to three engineering evaluations performed for boric acid found on reactor coolant system piping and components to determine whether the licensee properly applied applicable corrosion rates to affected components and properly assessed the effects of corrosion-induced wastage on structural or pressure boundary integrity.

3. Review one to three corrective actions performed for evidence of boric acid leaks that were identified. Confirm that these corrective actions were consistent ASME Code requirements and the licensee's corrective action program.

Additional Specific Guidance

As part of the preparation for the inspection of boric acid corrosion control, the inspector should consider reviewing Generic Letter (GL) 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," dated March 17, 1988, and Regulatory Information Summary 2003-13, "NRC Review of Responses to Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,'" dated July 29, 2003. The inspector should review licensee commitments made in response to GL 88-05. The inspector can review pages 4-25 and 4-26 of EPRI Technical Report 1000975, "Boric Acid Corrosion Guidebook, Revision 1: Managing Boric Acid Corrosion Issues at PWR Power Stations," dated November 1, 2001 (available at <https://www.epri.com/#/pages/product/1000975/>), to gain insights on corrosion-induced wastage rates.

Licensee boric acid evaluations of the configurations discussed below are considered a priority for review because of their possible higher corrosion rates. The following information refers to tests documented in EPRI Technical Report 1000975:

- Vessel Head. Boric acid dripping from sources above the head onto the carbon steel head will cause boric acid to concentrate, and the corrosion rate is sensitive to the flowrate onto the heated surface (reference pages 4-39 and 4-69 of EPRI Technical Report 1000975 for vendor tests).
 - Heated Carbon Steel Pipe. Boric acid dripping from sources above and onto heated and insulated pipe cause boric acid to concentrate (reference page 4-47 of EPRI Technical Report 1000975 for vendor tests).
 - Boric Acid Leakage Impingement. Boric acid steam/water impingement onto bolted configurations (can be typical for pump casing joints) creates a corrosive configuration for the bolts (reference page 4-49 of EPRI Technical Report 1000975 for vendor tests).
 - Elevated Temperature Flange Leakage. Boric acid leakage (approximately 0.1 gallon per minute) corrodes fasteners near the leak location for flanged joints operating at an elevated temperature (600 degrees Fahrenheit (F)) (reference page 4-78 of EPRI Technical Report 1000975 for vendor tests). For lower temperatures (180 degrees F), the corrosion of fasteners is much less.
- d. Steam Generator Tube Inspection Activities. This section applies to PWRs with scheduled SG examinations. Schedule this portion of the inspection towards the end of the SG inspection activities to better assess the condition of the SG after the examination of more SG tubes.

Verify that the licensee is monitoring SG tube integrity appropriately and is addressing mechanisms that could lead to primary-to-secondary tube leakages.

Specific Guidance

1. In Situ Pressure Testing

- a. If the licensee identifies repairable indications, review the licensee's in situ screening criteria developed for a sample of these repairable indications (consider reviewing criteria that apply to indications located in the SG tube free-span or U-bend areas). Determine whether the licensee's in situ pressure test screening criteria are in accordance with EPRI's guidelines. In particular, determine whether the assumed NDE flaw sizing accuracy is consistent with data from EPRI's examination technique specification sheet (ETSS) or other applicable performance demonstrations.
 - b. For those tubes that satisfied the initial screening criteria for an in situ pressure test, determine whether the appropriate tubes were selected for in situ pressure testing (in terms of specific tubes and number of tubes) considering the test data.
 - c. If performed, review plans for, and observe, if practical, in situ pressure testing activities and assess whether tubes are in situ tested in accordance with EPRI's in situ pressure test guidelines. Review methods for verifying that the correct tube is in situ tested, including the method for positioning the test equipment at an appropriate vertical tube elevation (if a local test is performed). Review the test procedure and determine whether the test was performed in accordance with the procedure and EPRI's in situ pressure test guidelines.
 - d. If performed, review in situ pressure test results to determine whether the tube integrity performance criteria were met. Review the in situ pressure test records (e.g., pressure versus time traces, pressure achieved, and hold times) to determine whether the test was completed as planned. Evaluate the results of the test against the performance criteria identified.
2. For a specific type of degradation (e.g., circumferential outside-diameter SCC at the expansion transition), compare the number of tubes affected and limiting flaw sizes with that predicted by the previous outage operational assessment to assess the licensee's prediction capability.
 3. Review the SG tube eddy current testing (ET) scope and expansion criteria to determine whether they meet technical specification (TS) requirements and commitments made to the NRC. Further, evaluate the ET scope to determine whether areas of potential degradation (based on site-specific experience and industry experience) are being inspected, especially areas that are known to represent potential ET challenges (e.g., top of the tube sheet, tube support plates, and U-bends)). Compare the licensee's SG tube inspection plan scope to the previous outage summary report and NRR-identified industry issues to verify that all areas of potential degradation have been included.
 4. If the licensee identified new degradation mechanisms, verify that its ET scope has fully enveloped the problem and that it has taken appropriate corrective actions before plant startup (e.g., additional inspections, in situ pressure testing, preventive tube plugging). The licensee identifies new degradation mechanisms by comparing the summary report of the previous outage results to the current

outage results. Notify NRR when a new degradation mechanism is discovered. NRR will assist in evaluating the corrective actions. If the SGs have been replaced, compare the first subsequent outage examination results to the pound per square inch data. Wear indications observed during the first inspection following SG replacement should not be considered a new degradation mechanism unless a large number of indications (greater than approximately 100 indications per steam generator) are detected or unless large through-wall extents are observed (greater than 30-percent through-wall).

5. If sufficient inspection resources exist (within baseline procedure estimates) and if site or industry experience indicates a potential for secondary-side internals structure degradation, review or observe secondary-side examinations. Review the licensee's corrective action taken in response to any observed degradation. Confirm that the licensee is conducting the secondary-side inspections in accordance with its governing documents (e.g., Steam Generator Management Program: Steam Generator Integrity Assessment Guidelines, Part 10).
6. If the licensee repairs tubes (e.g., installs plugs or sleeves), select a sample of tube repair locations to determine whether the licensee repaired the appropriate tubes. If the licensee has used tube repair methods other than those for the installation of tube plugs, determine whether the NRC has approved those repair processes for use at the site. To determine whether the licensee installed repairs at the appropriate tube locations, verify the installations by direct observation or by reviewing of licensee quality control measures implemented to ensure that the correct tube is located for repairs. Typically, two independent means (i.e., repairing robot encoder positions, manually counting tube rows or columns, and using machine vision systems) are used to locate tubes. If the licensee applies tube repair methods other than that for the installation of tube plugs, review the applicable docketed site correspondence to determine whether the repair processes being used were approved by the NRC (see TS) and were implemented and accepted consistent with the approved process.
7. Repair Criteria
 - a. Review a sample of repairable indications to determine whether the licensee is following the TS repair criteria. Typically, the TS repair limit is 40-percent through-wall. Confirm that the licensee uses depth sizing techniques that provide reasonable estimates of the degradation such that the typical TS repair limit can be implemented without a loss of tube integrity for the period of time between inspections. The licensee should only use a plug-on-detection approach for flaws if there are no qualified ETSSs to reliably size the indications.
 - b. Review a sample of repairable indications (e.g., I-Code (e.g. SCl – single circumferential indication, MAI – multiple axial indication)) identified by the licensee's vendor analysts to determine whether the licensee is applying a depth sizing repair criterion (typically 40-percent through-wall) for indications other than wear or axial primary water SCC at dented tube support plate intersections. If so, for these SG tubes with indications sized and returned to service, determine whether the NRC reviewed and approved the sizing method. These criteria may be acceptable and in accordance with the licensee's TS, although experience has shown, for example, that many types of intergranular attack SCC cannot be sized with a sufficient degree of

accuracy or reliability. In addition, this may indicate practices by licensees that are inconsistent with their response to GL 97-05, "Steam Generator Tube Inspection Techniques," dated December 17, 1997. If that is the case, contact NRR.

8. If SG leakage greater than 3 gallons per day was identified during operations or during postshutdown, review the licensee's actions to locate the source of the leakage (e.g., through secondary-side pressure test, visual inspection of plugs) and determine whether these actions are sufficient to identify the source of the leakage. In addition, determine whether corrective actions are planned or were taken to identify the cause of the leakage. IMC 0327, "Steam Generator Tube Primary-to-Secondary Leakage," provides additional guidance.
9. Review a sample of the licensee's vendor and EPRI "Pressurized Water Reactor Steam Generator Examination Guidelines" Appendices H and I ETSSs to determine whether the ET probes and equipment are qualified for detection or sizing of the expected types of tube degradation. For example, review the test configuration (i.e., frequency, coil selection, probe drive, and physical limitations). Verify that the appropriate ET probe (e.g., bobbin, pancake, or multicoil type) is used to detect the type of flaw that might be expected. Verify that the equipment has been calibrated in accordance with the ET procedure(s) and the ASME Code. In particular, focus the review on the site-specific factors potentially affecting the qualification of one or more techniques (e.g., equipment, data quality/noise issues, degradation mode).
10. If the licensee has identified loose parts or foreign material on the secondary side of the SG, review licensee corrective actions. Specifically, determine whether the licensee has performed or planned repairs or engineering evaluations of the affected SG tubes and has inspected the secondary side of the SG to remove foreign objects (if possible). If the foreign objects are inaccessible (and have not been removed), determine whether the licensee has performed an evaluation that considers the potential effects of object migration or tube fretting damage.
11. If the licensee has identified evidence that thermal-hydraulic conditions have changed significantly (e.g., significant reduction in steam pressure/output, difficulty in controlling secondary-side water level) or may change significantly (e.g., excessive deposit buildup as indicated by visual inspection or eddy current mapping), review the licensee's corrective actions.
12. Observe (if practical) a vendor/licensee analyst (a resolution analyst or qualified data analyst is recommended) reviewing one to five SG tubes with eddy current to determine whether proper ET analysis techniques were applied. If the data analysis is being performed off site at a vendor's facility, the inspector may observe that analysis at the offsite facility. If adequate expertise for this activity does not reside in the regional office, NRR should be contacted by telephone or e-mail to discuss the need for providing this resource. Inspections at an offsite vendor facility should be coordinated with the Vendor Inspections Branch to address the appropriate vendor requirements.

Additional Specific Guidance

If the safety significance of the operating experience so warrants, then, in consultation with the NRR Division of Materials and License Renewal (DMLR) and regional management, consider increasing the scope or depth of the SG baseline inspection beyond the IP's maximum estimated resources. Baseline inspection resources may be relocated from another baseline IP within the same cornerstone of safety to increase the scope or depth of inspection.

SGs with Alloy 600 tubes should receive a review as described in this section every SG examination outage. SGs with Alloy 690 tubes may not need this review unless considerable inservice time (e.g., more than 15 years since beginning commercial operation (or SG replacement, as appropriate) and more than two operating cycles since the last NRC inspection of the licensee's SG inspection activities) or other factors discussed below apply.

The following conditions may be a reason to increase the scope or depth of this inspection:

- a deteriorating SG tube material condition as evidenced by a significant increase in the number of flaws reported by the licensee during the previous SG tube examinations or an underprediction of the number or severity of flaws (based on information obtained from the licensee's most recent SG inspection summary report or its operational assessment)
- unmet SG tube performance criteria (i.e., operational leakage, structural integrity, or accident leakage) during the previous operating cycle
- PWRs with a history of primary-to-secondary leakage (e.g., more than 3 gallons per day) during the previous operating cycle
- a reported potential degraded condition (e.g., through NRC and industry information notices) resulting from the SG design, water chemistry, material properties, or newly identified degradation mechanisms

If none of these factors above apply, complete the steps in Sections 03.01d.1, 03.01d.3, 03.01d.4, 03.01d.7(a), 03.01d.8, 03.01d.9, 03.01d.10, 03.01d.11, and 03.01d.12.

Notify NRR/DMLR when any of the specific situations listed in Attachment 1 occur. Additionally, inspectors are encouraged to contact the NRR/DMLR when unexpected situations arise or when they need technical support.

In preparation for SG tube inspections, contact NRR/DMLR to determine whether additional reviews and focus are warranted. Consider reviewing the licensee's commitments in response to GL 97-05 and GL 97-06, "Degradation of Steam Generator Internals," dated December 30, 1997, and the most recent SG inspection summary report. Consider reviewing NRC generic communications, such as relevant information notices and regulatory information summaries. Become familiar with the industry SG program in Nuclear Energy Institute 97-06, "Steam Generator Program Guidelines," and several related EPRI reports. The EPRI guidelines referenced may not constitute NRC requirements or commitments (depending on the plant-specific details of the licensee's SG program), and the licensee may use technically acceptable alternative methods. If the licensee has deviated from the EPRI

guidelines, it should document the basis for the deviation. Although the guidelines represent an improvement over practices followed in the past, use of the guidelines alone may not ensure that the regulations will be satisfied.

Periodically, for plants that have SGs with active degradation or other SG issues, the NRR/DMLR staff will conduct a conference call with the licensee to discuss SG tube examination activities. When possible, participate in any NRR/DMLR scheduled conference calls between the NRC and the licensee's staff involving SG tube examinations. In addition, review summaries from previous conference calls. The NRR/DMLR staff should be able to identify these summaries. The information obtained during these calls will provide background and will help in planning inspection activities.

71111.08-04 REFERENCES

Inspection "best practices," training material, points of contact, and selected references are located on the internal NRC ISI Web site at <http://www.internal.nrc.gov/RES/projects/ISI/index.html> (nonpublic). Inspectors may find these references and resources useful; however, the information is predecisional, and the NRC does not require the use of these resources for inspection activities conducted as part of this procedure.

10 CFR 50.55a(g)(6)(ii)(D)

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

Cross-Reference of Generic Communications to IP 71111.08 and Inspection Resources (<http://drupal.nrc.gov/nrr/oqe/33992> (nonpublic))

Operating Experience Gateway (<http://drupal.nrc.gov/nrr/oqe> (nonpublic))

IHS Codes and Standards (<http://www.inlWAnal.nrc.gov/TICS/library/standards/ihs.html> (nonpublic))

NRC Technical Library (available at <http://www.internal.nrc.gov/TICS/library/index.html> (nonpublic))

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

END

Attachment 1
Steam Generator Tube Integrity Issues Requiring Further Evaluation

Promptly contact the U.S. Nuclear Regulatory Commission's (NRC's) Office of Nuclear Reactor Regulation (NRR), Division of Materials and License Renewal (DMLR), upon identification of any of the following situations:

- The selection of tubes to be in situ pressure tested is not consistent with the Electric Power Research Institute's (EPRI's) guidance (i.e., the number of tubes to be tested, specific tubes to be tested, or nondestructive examination uncertainty is not consistent with data from EPRI's examination technique specification sheet or other applicable performance demonstrations).
- The in situ pressure testing of flawed tubes is not successful in reaching the desired test pressure (e.g., main steam line break for an accident-induced leakage, 3 times the normal operating differential pressure and 1.4 times the main steam line break pressure for burst) because of tube failure/leakage or equipment problems/limitations.
- The estimated size or number of tube flaws detected during the current outage invalidates bounding assumptions from the previous outage operational assessment predictions.
- The licensee's use of depth sizing is inconsistent with its response to NRC Generic Letter 97-05, "Steam Generator Tube Inspection Techniques," dated December 17, 1997.
- The licensee is using tube repair criteria or a repair process that the NRC has not reviewed for use at this site (e.g., alternate tube repair criteria or sleeving process).
- Inspections or testing do not identify the source of primary-to-secondary leakage observed during the previous operating cycle or during plant shutdown.
- The licensee identifies new steam generator (SG) tube degradation mechanisms.
- The licensee reports levels of primary-to-secondary SG tube leakage exceeding 3 gallons per day.
- The regional office does not have adequate expertise to review eddy current indications data to determine whether proper eddy current testing analysis techniques were applied.
- There are indications of fluid-elastic instability in an SG or concerns with excessive deposit buildup that may result in fluid-elastic instability. Tube vibration induced by fluid-elastic instability can cause excessive tube wear.

Additionally, inspectors are encouraged to contact NRR/DMLR when unexpected situations arise or when they need technical support.

Attachment 2
Revision History for Inspection Procedure 71111.08

Commitment Tracking Number	Accession Number Issue Date Change Notice	Description of Change	Description of Training Required and Completion Date	Comment Resolution and Closed Feedback Form Accession Number (Predecisional, Nonpublic Information)
	04/03/00 CN 00-003	71111.08 has been issued to provide the minimum inspection oversight for determining the safety performance of operating nuclear power reactors.		
	10/11/01 CN 01-021			
	07/07/03 CN 03-023	Revised to change Section 05, Completion Status, to conform to the standard wording for sample size.		
	09/09/03 CN 03-033	Revised to add guidance on SG tube primary-to-secondary leakage. This guidance used to be contained in Part 9900.		
C-1 Reference: DBLLTF 3.3.4.2(3) C-2 Reference: DBLLTF 3.3.2.2(1)		Revision History Reviewed for last four years. Revised to add periodic inspection requirements and guidance for PWR vessel head penetrations and boric acid corrosion control, and to make other minor clarifications. In addition, the resource estimate for PWR inspection has been increased. DBLLTF Report: ML022760172		
	05/11/04 CN 04-013			
	ML071650361 10/04/07 CN 07-031	IP 71111.08 has been revised to incorporate best practices of ISI working group.		ML072400349

Commitment Tracking Number	Accession Number Issue Date Change Notice	Description of Change	Description of Training Required and Completion Date	Comment Resolution and Closed Feedback Form Accession Number (Predecisional, Nonpublic Information)
	ML083370044 03/23/09 CN 09-010	IP 71111.08 has been revised to address feedback form 71111.08-1319 by incorporating the changes to 10 CFR 50.55a(g)(6)(ii)(D)		
	ML092160233 11/09/09 CN 09-026	IP 71111.08 has been revised based on the 2009 ROP Realignment (added 12 hours to the resource estimate for BWR inspections) and to address feedback form 71111.08-1373 (editorial corrections) and 71111.08-1386 (clarification of sample requirements).		
	ML11262A023 11/23/11 CN 11-038	IP 71111.08 has been revised to as part of a 2011 ISI working group effort to incorporate best practices.		
	ML14266A049 11/13/14 CN 14-027	IP 71111.08 has been revised to incorporate Feedback forms 71111.08- 1899, 2038, 2039, 2044, and 2060		ML14302A323 ML14302A576 ML14303A018 ML14303A019 ML14303A020 ML14303A021
	ML16350A344 12/22/16 CN 16-035	IP 71111.08 has been revised to incorporate Feedback form 71111.08- 2224 and to clarify inspection requirements vs guidance in response to OIG Audit OIG-16-A-12.		71111.08-2224 ML16348A023

Commitment Tracking Number	Accession Number Issue Date Change Notice	Description of Change	Description of Training Required and Completion Date	Comment Resolution and Closed Feedback Form Accession Number (Predecisional, Nonpublic Information)
	ML18051A681 12/14/18 CN 18-043	<p>Reformatted the contents of the inspection procedure, removed redundant guidance related to the monitoring of steam generator leakage and provided a reference to the more comprehensive Inspection Manual Chapter (IMC) 0327, "Steam Generator Tube Primary-to-Secondary Leakage." Added guidance that inspectors should observe pressurized-water reactor vessel upper head penetration inspections.</p> <p>Eliminated redundancy and improved the inspection procedure in terms of plain writing.</p> <p>Relocated optional requirements to the guidance section to better align them with the sample completion requirements in Section 8.04 of IMC 2515, "Light-Water Reactor Inspection Program—Operations Phase."</p>		ML18094A298 71111.08-2275 ML18323A023 71111.08-2294 ML18109A128