

TECHNICAL BASIS FOR STEAM GENERATOR TUBE INTEGRITY FINDINGS

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0308.03J-01 PURPOSE

This document provides the technical basis for IMC 0609, Appendix J for the assessment of licensee performance deficiencies that result in failures to meet licensing bases and regulatory commitments as identified through the **Steam Generator** (SG) in-service inspection program.

0308.03J-02 RISK INCREASES CREATED BY STEAM GENERATOR TUBE DEGRADATION

Complete risk assessments of SG tube degradation require consideration of several types of core damage accident sequences:

1. Sequences initiated by spontaneous rupture of a tube. These sequences that result in core damage involve **multiple** combinations of equipment failures and human **errors**. Most of the core damage sequences **may** also result in containment bypass, **which is a LERF contributor**.
2. Sequences initiated by steam-side depressurization of a SG, which causes one or more degraded¹ tubes to rupture. These sequences result in core damage by similar combinations of equipment failures and human **error**. Containment is usually bypassed by the combination of tube rupture and **a steam-side depressurization outside of containment**.
3. Some core damage sequences **are** created by initiating events and equipment failures that have **no relationship to** the SG tubes. The core damage sequences of concern are characterized by relatively high reactor coolant system pressure and dry SGs at the time that fuel cladding oxidation occurs in the reactor core. These conditions subject the SG tubes to temperatures well above design values. At these abnormal temperatures, the tube material is weaker, and tube ruptures may occur if the tube strength has been degraded during normal operation. The effect of tube degradation on these sequences is an increase in the probability that containment bypass will occur for accidents already included in the base core damage frequency. **These sequences are referred to as**

¹In the context of this Appendix, the term “degraded” refers to any reduction in the structural/leakage integrity of a tube **from the installed pre-service condition**, regardless of the **flaw** depth. It is not intended to **apply only to “degraded” tubes that meet the repair criteria (e.g., 40 percent through-wall)** used in the standard Technical Specifications.

consequential steam generator tube ruptures (C-SGTR). They do not contribute to the core damage frequency, but they may contribute to the large early release frequency.

4. Sequences caused by failure of the reactor protection system to stop the nuclear chain reaction when feedwater is lost. These sequences are called loss of feedwater anticipated transients without scram (LOFW-ATWS) events. Failure of the reactor protection system can produce reactor coolant system pressures that are high enough to cause other failures that lead to core damage. If the tubes are degraded, the high pressure may also rupture some tubes as well, creating a containment bypass.

Historically, the first PRAs included only the first of the four sequences listed above, those initiated by spontaneous tube rupture events during normal operation. In the mid-1980s, NUREG-0844 (ML082400710) considered the pressure-induced ruptures in the second and fourth types of sequences, and NUREG-1150 (ML010140729), published in 1990, considered the high-temperature-induced ruptures in the third class of sequences. In the mid-1990s, NUREG-1570 (ML070570094) collected all these sequences in one place and evaluated them for a specific level of degradation.

In 2018, NUREG-2195 (ML16134A029) summarized consequential SG tube rupture (C-SGTR) analyses of replacement SGs with thermally treated Alloy 600 and Alloy 690 tubes. The report documented a method for a quantitative risk assessment of a temperature-induced C-SGTR during a severe accident (i.e., after the onset of core damage, which is referred to as a Type-I C-SGTR), and a pressure-induced C-SGTR during a design basis accident (DBA) event (i.e., before the onset of core damage, which is referred to as a Type-II C-SGTR). The study estimated the probability of containment bypass because of C-SGTR and assessed the fraction of containment bypass events that constituted LERF². It developed simplified LERF calculation methods and applied them to both Westinghouse and Combustion Engineering (CE) designed pressurized water reactor plants. In addition, the report used the generic stylized models to address C-SGTR related to DBA issues.

The SG flaw distributions used in NUREG-2195 were consistent with operating experience obtained around 2010 and were based on a statistical analysis of replacement SGs with an average operating history of 15 years. However, there still is a problem with making the risk model logic for these sequences sensitive to the current degree of degradation of the SG tubes in a specific plant. Nearly all PRAs use the same frequency for the spontaneous rupture of a tube during normal operation. Based on deterministic approaches and/or fracture mechanics, those plants with known tube degradation problems should have higher spontaneous rupture frequencies than plants with new SGs and no degradation observed to date. However, to some degree, the use of the average empirical frequency is justified by our experience that all tube rupture events have been unexpected when they occurred. And, it will remain so, because a plant would not knowingly be operated with tubes that had degraded to the point that they cannot withstand three times the stresses of normal operation. Even when an inspection has revealed that the factor-of-three margin required by the plant's licensing basis has not been maintained during a previous operating cycle, it is difficult to relate the degree of observed degradation to a quantitative increase in the probability that the tube degradation would have reached the spontaneous rupture point in that cycle. This makes it infeasible to base the Significance Determination Process (SDP) color on the unquantifiable fluctuations in

² Not all containment bypass events happen "early" in the accident timeline and therefore some bypass events do not contribute to LERF. Early refers to releases from containment in a time frame prior to the effective evacuation of the close-in population such that there is potential for early health effects (See IMC 0609, Appendix H). Effective evacuation times are plant specific.

spontaneous rupture frequency for a specific plant. This and other challenges with risk quantification will be discussed in a later section.

0308.03J-03 TUBE INTEGRITY REQUIREMENTS

The SG tube integrity is maintained by meeting the performance criteria for tube structural integrity, accident induced leakage integrity, and operational leakage, as defined in the technical specifications.

The operational experience of the first generation SGs in the US, with Alloy 600 mill-annealed tubing, showed high susceptibility to pitting, wastage, and stress corrosion cracking. Changes to primary and secondary chemistry programs, along with thermally treating the Alloy 600 tubing, resulted in much better performance in the second generation of SGs installed in the US. Replacement SGs with Alloy 690 thermally treated tubing were first installed in the US fleet in 1989, and to date, the tubing in these SGs has had excellent in-service results, with tube wear being the only observed degradation mechanism.

With three different tubing alloys in service that have significant differences in performance, it was recognized in the 1990s that the prescriptive technical specifications in use were not well suited to the wide variety of tubing performance and ineffective at ensuring tube integrity was being maintained between inspections. To address these shortcomings, the industry developed a variety of technical guidelines on matters related to maintaining steam generator tube integrity (References 1–6), which are implemented through NEI 97-06, the “Steam Generator Tube Integrity Program.” This initiative integrated the industry guidelines into a performance-based program for ensuring tube integrity that provided the flexibility to maintain tube integrity across a wide range of SG performance. Under this approach, the condition of the tubing is periodically assessed relative to performance criteria that are commensurate with tube integrity and with the current plant licensing bases. The new tube integrity performance criteria were adopted in the standard technical specifications in 2005 and include:

1. Structural Integrity Performance Criterion:

All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cooldown), all anticipated transients included in the design specification and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

Discussion: For axial cracks in all types of steam generators, this criterion typically is interpreted as a requirement to be capable of maintaining a pressure differential equal to the greater of either 3 times the normal operating pressure difference across the tube wall, ($3x\Delta P_{NO}$), or 1.4 times the pressure difference of the most limiting design basis accident, which is frequently the main steam line break accident ($1.4x\Delta P_{MSLB}$). However,

for circumferential cracks, other sources of loading, apart from differential pressure loads, may contribute to burst. Potential additional loads include bending stresses induced by LOCAs, safe shutdown earthquakes, and main steam line break. For the straight-tube SGs, the additional loads also include axial loads induced by differential thermal expansion/contraction between the tubes and the shell during the temperature/pressure transients resulting from design basis accidents. For a given flaw, the structural criteria require that licensees determine whether such nonpressure loading sources may impact the burst pressure. Where it is determined that such may be the case, licensees must directly consider the impact of such loads on burst. The methodology to be employed for considering the impact of nonpressure loadings will be documented to NRC at the time the structural criterion is incorporated into the plant technical specification. That should make the importance of specific additional loads (beyond the ΔP loads) apparent for any design-basis accident analyses for plants where these considerations apply. For analysis of sequences involving steam generator tube rupture induced during severe accidents, only the ΔP loads appear to be relevant, using current knowledge.

2. Accident-Induced Leakage Criterion:

The primary-to-secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed [1 gpm] per SG [, except for specific types of degradation at specific locations as described in paragraph c of the Steam Generator Program].

Discussion: During the most limiting design basis accident, the calculated rate of leakage (accident leakage) is limited to values consistent with the licensing basis analyses. The accident leakage limits are often plant-specific and typically are limited to 1 gallon per minute (gpm) or less. This typically applies to a single steam generator under the conditions assumed for a design-basis main steam line break accident. (For a few specific types of degradation in specific, confined locations, the NRC has approved alternate repair criteria that allow for specific higher accident leakage limits, using hypothetical leakage calculations that do not take credit for the physical effects of the confining structures.)

3. Operational Leakage Criterion:

The operational LEAKAGE performance criterion is specified in LCO 3.4.XX, "RCS Operational LEAKAGE."

Discussion: The current value of 150 gallons per day (gpd) was first implemented in 2005 and has been found by experience to be an appropriate value that minimizes the probability of a tube that is exhibiting leak-before-break type behavior of progressing to a rupture before plant shutdown, without being unnecessarily burdensome. Some units have operational leakage limits that are significantly lower than the 150 gpd value in the standard technical specifications. While operational leakage can sometimes be identified as coming from a specific SG, the susceptibility of the leak source to rupture is not known prior to shut down. Some flaws have leaked before rupturing and some have ruptured without leaking first.

Licenses currently determine their compliance with the first two criteria by calculations based on SG tube in-service inspection (ISI) data and/or by in situ pressure testing, whenever SG inspections are performed.

Inspection findings that involve failures to meet either of the first two requirements can be evaluated in terms of the risk that is incurred. Findings that involve operational leakage are not amenable to risk assessment until the cause of the leakage has been found and it is assessed with respect to the first two requirements.

0308.03J-04 RELATIONSHIPS BETWEEN TUBE DEGRADATION AND THE REACTOR OVERSIGHT PROCESS "CORNERSTONES"

When tube degradation reaches a level that prevents a tube from meeting its required pressure retention capability (typically $3x\Delta P_{NO}$ or $1.4x\Delta P_{MSLB}$), it is beginning to become susceptible to the accident sequences that induce tube rupture by high temperatures that would occur during core damage accidents. Excessive tube leakage during severe accident sequences may also alter the course of the sequence and cause gross tube failure, creating a containment bypass event. This degree of degradation also makes the tube susceptible to rupture due to the extremely high reactor coolant system (RCS) pressures that can occur in some ATWS accident sequences, creating an increased probability for containment bypass for those sequences, too. Thus, this degree of degradation affects the "Barrier Integrity Cornerstone."

When tube degradation reaches the level that allows a tube to rupture under the conditions of a design-basis main steam line break event, it has become susceptible to failure during anticipated operational occurrences such as steam system depressurization events. This is still considered a degradation of the "Barrier Integrity Cornerstone," but it involves additional terms of the risk equation to quantify the effect.

Finally, when degradation reaches the level that allows a tube to rupture during normal operation (or it could have ruptured if the pressure on the tube had been slightly increased by a practice used in normal operation), then there is an effect on the "Initiating Events Cornerstone" as well as the "Barrier Integrity Cornerstone."

0308.03J-05 TREATMENT OF SG TUBE ISI ISSUES THAT DO NOT PROVIDE DIRECT KNOWLEDGE OF TUBE CONDITION

Except for those instances when tubes leak or rupture during normal operation, our knowledge of tube condition is limited to the results of the periodic tube inspections conducted by the licensees, sometimes supplemented by in situ pressure tests of a few tubes. If those inspections are not conducted in a manner that is adequate to detect tube degradation before it reaches significant levels, then a substantial latent risk increase can occur.

Regulatory requirements do not specifically address many of the technical aspects of how the licensee's SG tube ISI activities are conducted. Industry guidance has been developed for selecting specific ISI methods and practices that are adequate for specific conditions in SG tubing. The overall intent of NRC requirements and industry guidance is to conduct tube ISI with sufficient frequency and detection capability to provide reasonable assurance that every tube will continue to satisfy all tube performance criteria until the next inspection.

Many NRC inspection issues are related to questions about the adequacy of the licensee's ISI and condition monitoring methods and practices with respect to the licensees' obligation under 10 CFR 50, Appendix B Criterion 16 to identify conditions adverse to quality. In cases where tube ISI and condition monitoring has not revealed any violation of the tube performance criteria, some NRC findings may still raise doubts about whether the ISI has been adequate to assure that all tubes meet the criteria, or that they will continue to do so by the end of the next inspection interval. Examples of this type of finding are: 1) the inspection technology used is not sensitive to a type of tube degradation that has violated the tube performance criteria at similar plants; 2) the "noise" level in the inspection signal is unusually large at a plant, and could mask the signal of a flaw that could grow to violate a performance criterion before the next inspection; 3) screening criteria for selecting tubes for in situ pressure testing does not fully account for flaw size measurement error associated with nondestructive examination technologies, and 4) the number and/or severity of flaws found significantly exceeded what was expected, based on the previous operational assessment.

For these types of inspection issues, the probability of tube failure is unknown because there is no adequate basis for assessing the physical condition of the tubes. In theory, if the NRC had data on the number of times that the tubes had degraded to specific performance levels for many randomly selected cases where inspection had been inadequate, the NRC at least could make an estimate of the probability that the tubes have degraded (or will degrade) to various levels due to the lack of adequate inspection. However, that type of data is not available, so the probability of tube degradation to specific levels is not known as a function of the degree or type of licensee ISI performance problems.

Consequently, inspection issues related to inadequate ISI methods and practices cannot be assessed for risk significance when the NRC has no direct knowledge of the degree of tube degradation that has occurred. Therefore, the reactor oversight process (ROP) was developed in a manner that provides a means, other than quantitative risk assessment, for the NRC staff to allot increased inspection effort based on this type of inspection issue.

In accordance with the SG Action Plan, modifications were made to the baseline inspection procedures that facilitate appropriate inspector response to issues involving inadequate SG tube ISI. In addition to the infeasibility of assigning a risk increase to an unknown tube condition, there was a need for more rapid agency response than was achieved through the SDP procedures. Since licensees can inspect the tubes only when the reactor is shut down and the SGs are opened, there is a very limited period during which the tube ISI is scheduled. If a licensee appears to be performing the ISI in an inadequate manner, timely agency and licensee responses are important to balance unnecessary licensee burden with maintaining public safety. The inspection procedures accomplish this by allocating additional effort to SG ISI from the band of allowable inspection effort within the base inspection program. Also, identification of these types of issues by regional staff will result in notification and involvement of headquarters specialists in the Division of New and Renewed Licenses (DNRL) in the Corrosion and Steam Generator Branch (NCSG), which will focus additional effort by headquarters staff on the issues identified.

0308.03J-06 CONDITIONAL CORE DAMAGE PROBABILITY ESTIMATES FOR SG TUBE FAILURE EVENTS AND DEGRADED CONDITIONS

When risk-significant tube degradation is revealed by a tube failure during normal operation or by ISI results, the agency responds in accordance with the provisions of Management Directive 8.3. That directive specifies that the level of response is to be based on deterministic

criteria and risk significance, “such as conditional core damage probability (CCDP).” In the case of SG tube degradation, the more appropriate risk measure would be the conditional large early release probability (CLERP) of radioactive materials during a core damage accident. As discussed previously, SG tube degradation and failure events can substantially increase public risk with little or no increase in the core damage frequency.

The probabilistic calculations that are required to quantify the risk increase for the SDP process are essentially the same as those used to calculate a CCDP or CLERP. The following discussion will serve to illustrate both processes needed to support the ROP.

0308.03J-07 QUANTIFICATION OF RISK INCREASES ASSOCIATED WITH SG TUBE DEGRADATION

As previously discussed, there are several types of accident sequences that can increase core damage frequency (CDF) and/or large early release frequency (LERF) estimates due to tube degradation. As the degree of degradation becomes more severe, more of these sequences contribute to the risk increase because tube failure probabilities significantly increase for the physical conditions relevant to those sequences.

When tube degradation has reached the point that one or more tubes cannot withstand three times the pressure differential that occurs in normal operation ($3\Delta P_{NO}$), a tube integrity performance criterion has been violated. The $3\Delta P_{NO}$ level varies significantly from plant to plant, depending on the plant design and the number of tubes that have been plugged. It is approximately 4000 pounds per square inch (psi). The risk significance of the violation needs to be assessed as part of the ROP. However, the accident sequences to which tubes are vulnerable at approximately the $3\Delta P_{NO}$ level of degradation are not design-basis accidents. They include ATWS sequences and core damage sequences during which the fuel clad oxidizes while the RCS is not yet depressurized and the SGs are dry (high/dry core damage sequences). The $3\Delta P_{NO}$ criterion was not established as the threshold for susceptibility to these sequences. Risk may increase before or after the tubes have degraded to this level, depending on several aspects of the plant design and current core fuel load parameters. This complicates the concept of assessing the risk of the licensee’s “performance deficiency” because degradation below the 3 delta-P criteria is accepted as part of the plant’s baseline risk. Thus, to be exact, the SDP risk assessment should subtract the risk at the $3\Delta P_{NO}$ degree of degradation from the risk at the level of degradation found.

Previously, this presented a problem, because the capability for estimating risk from tube degradation for the high/dry sequences was not developed sufficiently to make such fine distinctions. In NUREG-1740, March 2001, the Advisory Committee on Reactor Safeguards Ad Hoc Subcommittee on a Differing Professional Opinion concluded that, “The staff does not currently have a technically defensible analysis of how steam generator tubes, which may be flawed, will behave under severe accident conditions in which the reactor coolant system remains pressurized.” As noted in the NRC memo that established the SG Action Plan on November 16, 2000 (ML003770259), there existed at the time, several crucial gaps in the technical knowledge of SG tube performance during severe accidents. The SG Action Plan consolidated several ongoing activities related to SG tube integrity to ensure the issues were appropriately tracked and dispositioned, and to ensure an integrated SG regulatory framework was developed that was effective and efficient.

Following an ATWS initiating event, existing SG tube degradation may lead to high/dry core damage sequences. Thus, SDP risk assessments for all levels of degradation that violate tube

integrity performance criteria will need to include these sequences. When degradation has become **severe** enough that tubes are susceptible to steam line breaks or normal operational stresses, the risk assessment results will probably be dominated by the additional sequences. For example, even when a tube failure event during normal operation revealed that the Indian Point Unit 2 plant was susceptible to **all** the sequences that can be influenced by tube degradation, it still was necessary to include the high/dry sequences **to** determine the appropriate “color.”

Similarly, the accident leakage limit originally was established for showing conformance with 10 CFR 100 dose guidelines during design basis accidents, without an understanding of the impact of tube leakage on the progression of “high/dry” type severe accidents. So, present knowledge does not provide a clear basis for estimating what the additional risk is at the regulatory limit for accident leakage.

Because of the need to address these sequences and the current problems with the methods for analyzing them, it is not **currently** feasible to produce plant-specific, SDP tools for SG tube degradation issues. This SDP provides a generic tool for assigning a preliminary “color” to inspection findings when tube degradation has violated one or more tube integrity performance criteria. Inspectors should request assistance from headquarters staff who are familiar with the most current knowledge.

The SDP places typical tube degradation inspection findings in broad “color” groups. According to the ROP, Green issues are those that have a ΔLERF below 1×10^{-7} /reactor-year. White findings are in the ΔLERF range between 10^{-7} and 10^{-6} /reactor-year. Yellow findings are in the ΔLERF range between 10^{-6} and 10^{-5} /reactor-year. Red findings are those with ΔLERF above 10^{-5} /reactor-year.

Reactors **with once-through SGs (OTSGs) (a Babcock and Wilcox (B&W) design)** are listed separately for some findings because they have different frequencies for some important sequences. High/dry core damage sequences are less likely to produce high tube temperatures in **OTSG** designs than in the U-tube SG designs in Westinghouse and **CE** plants. Also, **OTSG** designs have **a** higher frequency of steam-side depressurization events.

Because tube degradation that violates the $3\Delta P_{\text{NO}}$ criterion may make the tubes susceptible to high/dry core damage sequences that have a frequency in the low- 10^{-5} /reactor-year range, any of these colors **are credible**. However, the degree of degradation beyond the performance criterion, the fraction of a year over which this degree of degradation existed, and many plant-specific factors are important determinants for the risk in a specific case. Experience and engineering judgment have been used to assign a White significance level for findings of single tubes that are susceptible only to these sequences. When multiple tubes have degraded below the structural integrity performance criteria, or a single tube has degraded below that level in multiple cycles, it is more likely but not certain that the total risk will fall into the Yellow range. For that reason, **Table 1 in IMC-0609, Appendix J, “Steam Generator Tube Integrity Findings Significance Determination Process”** indicates only **“Perform a Detailed Risk Evaluation”** for findings involving multiple instances of exceeding the structural integrity criteria. Babcock and Wilcox plants with one tube that violates the structural integrity criteria are also listed under the **“Perform a Detailed Risk Evaluation”** category because the lesser degree of susceptibility for the once-through design to the high/dry sequences provides a substantial potential for a Green result.

When one or more tubes has degraded to the point that they cannot sustain the pressure differential created by a steam-side depressurization event (ΔP_{MSLB}), it is necessary to include

those sequences in the risk assessment as well. The threshold for this sequence is the lowest operable pressurizer valve setpoint. In some plants that will be a power-operated relief valve; for other plants where the PORVs are blocked or not installed, it will be a safety valve setpoint. Again, **OTSG designs** differ significantly from the **U-tube designs**. The plants with **OTSGs** have experienced several events that produced pressures near these thresholds shortly after a reactor trip. The plants with **U-tube SGs** have experienced a relatively smaller number of events (considering the numbers of each design in operation), and none that the **NRC** are currently aware of produced such high pressure-differentials across the tubes after a reactor tripped from normal operation. However, **U-tube SGs** are known to have produced similarly high pressure-differentials across the tubes under other operational situations and lesser pressure differentials following trips from full power. On this basis, the frequency of high pressure differentials on the tubes due to steam-side depressurizations is estimated at about 10^{-2} /reactor-year for **OTSG designs** and about 10^{-3} /reactor-year for the U-tube designs. When degradation has made the tubes susceptible to rupture if a steam generator depressurizes, a depressurization event becomes much more difficult for the operators to handle. **As noted in section 7.4.4 of NUREG-2195, when considering the difficulty of the combined primary and secondary system failures, the probability of the plant operators failing to diagnose the occurrence of a C-SGTR after the steam line break (SLB) scenario was estimated using the Standardized Plant Analysis Risk Human Reliability Analysis (SPAR-H) worksheet to be about 2.5×10^{-2} .** Therefore, a tube in a Westinghouse steam generator that was susceptible to a C-SGTR from a steam-side depressurization was estimated to produce a Δ CDF/ Δ LERF in the range of $<1 \times 10^{-9}$ to 3.4×10^{-7} . For a CE steam generator, a tube that was susceptible to a C-SGTR from a steam-side depressurization was estimated to produce a Δ CDF/ Δ LERF in the range of $<1 \times 10^{-9}$ to 5.3×10^{-7} .

The initiating event frequency for SG tube rupture used in NUREG-2195 was based on NUREG/CR-6928, "Industry-Average Performance for Components and Initiating Events at U.S. commercial Nuclear Power Plants," which did not differentiate between straight-tube and U-tube SG performance. The Δ CDF/ Δ LERF values for the Westinghouse and CE plants in NUREG-2195 (as shown above), are lower than the values previously used for a "preliminary determination" in Table 1 of IMC 0609 Appendix J, "Steam Generator Tube Integrity Findings Significance Determination Process."

Since OTSGs were not analyzed separately in NUREG-2195, a tube susceptible to a steam-side depressurization for a year **should still be** estimated to produce a Δ CDF/ Δ LERF of about 10^{-4} /reactor-year **and be** assigned a preliminary Red.

Finally, the amount of degradation that makes a plant susceptible to tube rupture during normal operation has been assigned a Red color for all plant designs. Included in this color are tubes that would rupture at pressure differentials that are often encountered during normal plant operations, even if the tube did not actually rupture because the actual operations did not happen to include those pressures while the tube was susceptible. A probability of about 0.1 for encountering those pressures is sufficient to keep the Δ LERF estimate in the Red category. The pressure **differential** threshold for this category is about 1600 psi for many plants. However, some plants may subject their tubes to much higher values, so plant-specific information should be used.

This appendix includes a Green criterion for plant operation at-power with one or more tubes that should have been repaired or plugged but were not. This criterion is intended to apply to either 1) a licensee's failure to identify a flaw that should have been identified as meeting the plugging limit with the data obtained in a previous inspection, or 2) a licensee's inadvertent

failure to plug a tube that was identified for plugging. This criterion does not apply to the situation where a tube that is identified as flawed in a subsequent inspection can be found to have exhibited a detectable signal in the previous inspection data, unless the data from the previous inspection clearly indicates that the flaw exceeded the plugging limits at the time of the previous inspection. However, if the flaw causes the tube to fail the $3x\Delta P_{NO}$ criterion when it is found in the subsequent inspection, then SDP criteria listed under White, Yellow or Red will still apply. If it appears that a previous inspection was inadequate to properly characterize the condition of the tubes or that the inspection interval was too long to assure continued compliance with the performance criteria based on the data obtained in the last inspection, the significance determination should be based on the nature and degree of the inspection process inadequacy, rather than on the worst flaw found by an inadequate ISI effort.

Findings involving accident leakage have been placed in the “Perform a Detailed Risk Evaluation” category of the table because the wide range of potential leak rates can result in risk levels that range from the Green into the Red categories. Individual findings that involve degradation that would exceed the accident leakage performance criterion under design basis accident conditions should be referred to a regional senior risk analyst, with assistance from NRR/DRA/APOB as necessary. The analyst will compare the finding parameters to the latest information available from the ongoing research efforts to select an appropriate color for the Detailed Risk Evaluation analysis.

The table does not include entries for exceeding the operational leakage limits because that does not necessarily mean that a significant risk increase has occurred. When that limit is exceeded, the licensee must shut down the plant and find the cause. Once the cause is determined, it will be possible to characterize the problem in terms of the probability for rupture and the estimated rate of leakage at the specific conditions associated with the risk-significant accident sequences. So, the significance can then be based on the entries for those findings in the table.

The OTSGs have an additional issue that is not relevant to the U-tube designs. The straight tubes in the OTSGs can be put into tension or compression by thermal transients in the RCS, due to changes in the temperature difference between the tubes and the SG vessel shells, which are rigidly connected, parallel mechanical structures. For transients that cool the tubes significantly more rapidly than the shells, the tubes may experience axial tension loads that are high enough to cause tube failure at significant circumferential cracks. At present, significant circumferential cracking is not being found in the free span of OTSG. If it is found, it should be carefully evaluated for the thermal loads as well as the pressure loads. The SDP does not attempt to assign a color to a finding of significant circumferential cracking in the free span of the tubes in OTSGs, but it does include a note to alert inspectors to submit the finding for a Detailed Risk Evaluation if it ever occurs.

The assigned colors for a Detailed Risk Evaluation assume that the releases from core damage events with failed tubes have characteristics that are appropriately treated as part of the large, early release frequency. As modeled by the NRC in NUREG-1150, this is usually the case. Some plant’s individual plant examinations (IPEs) have found a few sequences that the agency agreed are not appropriate to treat as part of the LERF. However, many plant IPEs treated some steam generator tube rupture sequences as non-LERF for reasons that the agency does not support. For example, Indian Point Unit 2 IPE treated tube rupture sequences as non-LERF if the core melts while the SG relief valves function to control SG steam-side pressure. The licensee’s logic is that their modeling shows that the resulting radioactive iodine release is only about 8 percent of the core inventory, which is less than the 10 percent threshold for LERF

sequences proposed by the Electric Power Research Institute (EPRI). However, the staff's model for the same sequences in NUREG-1150 estimated that 14 percent of the core iodine inventory would be released. Further, the agency has never accepted the proposed 10 percent threshold as an appropriate definition for LERF. Therefore, when using an IPE for **performing a Detailed Risk Evaluation**, it will be necessary to closely evaluate the bases for the LERF designations of the contributing sequences. Because there is a factor of a few thousands difference for the iodine release fraction between an SGTR core damage sequence and the core damage sequence where the containment function is successful, our current guidance is to treat sequences as if they are LERF if they are anywhere near the LERF-type releases in magnitude and timing. Excluding sequences from the LERF category **based on** small variations in the estimation of the core iodine fraction released is **inappropriate**, considering the uncertainty of those small differences and the large difference between the magnitude of the LERF-type releases and the contained-sequences releases.

Technical Contacts:

<mailto:>

Paul Klein, NRR/DNRL/NCSG, (301) 415-4041, paul.klein@nrc.gov

Andrew Johnson, NRR/DNRL/NCSG, (301) 415-1475, andrew.johnson@nrc.gov

0308.03J-08 REFERENCES

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IMC 0609, Appendix J, "Steam Generator Tube Integrity Findings Significance Determination Process"

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Plants with Thermally Treated Alloy 600 and 690 Steam Generator Tubes,"
(ML16134A029), U.S. NRC, May 2018

END

Attachment 1: Revision History for IMC 0308, Attachment 3, Appendix J

Commitment Tracking Number	Accession Number Issue Date Change Notice	Description of Change	Training Required and Completion Date	Comment Resolution and Closed Feedback Form Accession Number (Pre-Decisional, Non-Public Information)
N/A	05/06/04 CN 04-010	Revision History reviewed for last 4 years. IMC0308 Basis Document was created for SDP Appendix J - Steam Generator Tube Integrity.	No	N/A
N/A	ML102500256 07/06/11 CN 11-011	Basis was revised to support revisions made in SDP Appendix J, which removed guidance to open an unresolved item for ISI Programmatic findings and changes issues that were "to be determined" to "assess in Phase 3" (ROPFF0609J-1356).	No	N/A
N/A	ML21246A285 02/02/24 CN 24-004	Revised to reflect completion of the Steam Generator Action Plan, addition of new and updated industry references, and revisions to other NRC Inspection Manual Chapters. Additional formatting changes to meet guidance in IMC 0040.	None required	ML21246A283 ML24003A832