Tennessee Valley Authority, 1101 Market Street, Chattanooga, Tennessee 37402

CNL-20-010

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10 CFR 50.90

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555-0001

Sequoyah Nuclear Plant Unit 1
Renewed Facility Operating License No. DPR-77
NRC Docket No. 50-327

Subject: **Application to Revise Sequoyah Nuclear Plant (SQN) Unit 1 Technical Specifications for Steam Generator Tube Inspection Frequency (SQN-TS-20-01)**

In accordance with the provisions of Title 10 of the *Code of Federal Regulations* (10 CFR) 50.90, "Application for amendment of license, construction permit, or early site permit," Tennessee Valley Authority (TVA) is submitting a request for an amendment to Renewed Facility Operating License No. DPR-77 for the Sequoyah Nuclear Plant (SQN) Unit 1.

The proposed license amendment request (LAR) revises SQN Unit 1 Technical Specifications (TS) 5.5.7, "Steam Generator (SG) Program," and SQN Unit 1 TS 5.6.6, "Steam Generator Tube Inspection Report," to reflect a proposed change to the required SG tube inspection frequency from every 72 effective full power months (EFPM), or at least every third refueling outage, to every 96 EFPM. Because SQN Unit 1 has an 18-month operating cycle, 96 EFPM normally equates to every fifth refueling outage.

TVA is scheduled to perform the next SQN Unit 1 SG tube inspection during the SQN Unit 1 Cycle 24 Refueling Outage (U1R24), which is scheduled to commence on April 10, 2021. TVA has been involved in the development of Technical Specification Task Force (TSTF)-577, "Performance Based Frequencies for Steam Generator Tube Inspections," along with meetings between the industry and the Nuclear Regulatory Commission (NRC). However, the schedule for the development and NRC review and approval of TSTF-577 does not support TVA's schedule for the proposed license amendment.

The operational experience of the SQN replacement SGs (RSGs), as described in the enclosure to this submittal, demonstrates that the proposed change to the schedule for the SG inspections is appropriate and will result in a reduction of dose to personnel and risk to the plant. Furthermore, the SQN Unit 1 RSG operational assessment and experience supports the proposed TS changes.

The enclosure to this submittal provides a description and technical evaluation of the proposed change, a regulatory evaluation, and a discussion of environmental considerations. Attachment 1 to the enclosure provides the existing SQN Unit 1 TS pages marked-up to show the proposed changes. Attachment 2 to the enclosure provides the existing SQN Unit 1 TS pages retyped to show the proposed changes. There are no TS Bases changes.

TVA has determined that there are no significant hazard considerations associated with the proposed change and that the change qualifies for a categorical exclusion from environmental review pursuant to the provisions of 10 CFR 51.22(c)(9). In accordance with 10 CFR 50.91, "Notice for Public Comment; State Consultation," TVA is sending a copy of this letter and the enclosure to the Tennessee Department of Environment and Conservation.

TVA requests approval of the proposed license amendment within one year from the date of this submittal, with implementation within 30 days following NRC approval in order to support the SQN U1R24 outage, during which the SQN SG tubes are scheduled to be inspected.

There are no new regulatory commitments associated with this submittal. If you have any questions about this proposed change, please contact Kimberly D. Hulvey, Fleet Licensing Manager, at (423) 751-3275.

I declare under penalty of perjury that the foregoing is true and correct. Executed on this 24th day of February 2020.

Respectfully,

James T. Polickoski
Director, Nuclear Regulatory Affairs

Enclosure:

Evaluation of Proposed Change

cc (Enclosure):

NRC Regional Administrator – Region II
NRC Project Manager – Sequoyah Nuclear Plant
NRC Senior Resident Inspector – Sequoyah Nuclear Plant
Director, Division of Radiological Health – Tennessee State Department of Environment and Conservation

Enclosure

Evaluation of Proposed Change

Subject: **Application to Revise Sequoyah Nuclear Plant (SQN) Unit 1 Technical Specifications for Steam Generator Tube Inspection Frequency (SQN-TS-20-01)**

CONTENTS

ATTACHMENTS

1. Proposed TS Changes (Mark-Ups) for SQN Unit 1
2. Proposed TS Changes (Final Typed) for SQN Unit 1

1.0 SUMMARY DESCRIPTION

In accordance with the provisions of Title 10 of the *Code of Federal Regulations* (10 CFR) 50.90, "Application for amendment of license, construction permit, or early site permit," Tennessee Valley Authority (TVA) is requesting a license amendment to Renewed Facility Operating License No. DPR-77 for the Sequoyah Nuclear Plant (SQN) Unit 1. The proposed license amendment request (LAR) revises SQN Unit 1 Technical Specifications (TS) 5.5.7, “Steam Generator (SG) Program,” and TS 5.6.6, “Steam Generator Tube Inspection Report,” to reflect a proposed change to the required SG tube inspection frequency from every 72 effective full power months (EFPM), or at least every third refueling outage, to every 96 EFPM. Because SQN Unit 1 has an 18-month operating cycle, 96 EFPM normally equates to every fifth refueling outage.

The operational experience of the SQN replacement SGs (RSGs), as described in this enclosure, demonstrates that the proposed change to the schedule for the SG inspections is appropriate and will result in a reduction of dose to personnel, and risk to the plant. The SQN Unit 1 RSG operational assessment (OA) and experience supports the proposed TS change.

2.0 DETAILED DESCRIPTION

2.1 PROPOSED CHANGES

The following is a detailed description of the proposed SQN Unit 1 TS changes.

- TS 5.5.7 d.2 is revised as follows:

  After the first refueling outage following SG installation, inspect each SG at least every ~~72~~96 effective full power months ~~or at least every third refueling outage (whichever results in more frequent inspections)~~.. In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a and b~~, c, and d~~ below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated.

- TS 5.5.7 d.2.b) is revised as follows:

  “During the next 96~~120~~ effective full power months, inspect 100% of the tubes. This constitutes the second and subsequent inspection periods.

- TS 5.5.7 d.2 c) and d) are being deleted.

- TS 5.6.6 is being revised to add the following new reporting requirement

  i. Discuss trending of tube degradation over the inspection interval and provide comparison of the prior operational assessment degradation projections to the as-found condition.

Attachment 1 to this enclosure provides the existing SQN Unit 1 TS pages marked-up to show the proposed changes. Attachment 2 to this enclosure provides the existing TS pages retyped to show the proposed changes. There are no TS Bases changes associated with this LAR.

2.2 CONDITION INTENDED TO RESOLVE

The operational experience of the SQN RSGs, as described in Section 3.0 to this enclosure, demonstrates that the proposed change to the schedule for the SG inspections is appropriate and will result in a reduction of dose to personnel and risk to the plant. Table 1 shows the current outage schedule and the proposed schedule for SG inspections. Overall, the proposed change will result in two less instances of SG inspections through the life of the plant while still accomplishing the 100 percent (%) inspection of the tubing within the sequential periods.

A significant reduction in dose will be achieved through less SG inspection outages. The dose reduction will be the result of less SG activities and additional shielding of personnel during refueling outages because secondary side water covering the SG tube bundle provides shielding and reduces exposure for all activities in containment. Typical dose values for SG inspections can vary depending on outage scope and activities. However, during the U1R21 SG inspection outage the associated activities accounted for 22.6 person-rem, which was approximately 22% of the total outage dose. Assuming that the same U1R21 dose occurred in future SG inspection outages, the avoided dose for SQN Unit 1 personnel under the proposed amendment and planned SG inspection schedule would be at least 45.2 person-rem over the remaining life of the plant.

Many of the evolutions performed for SG inspections pose an increased risk to the plant and personnel due to high dose (e.g., heavy lifts, confined space activities). An example of plant configuration improvement and risk reduction, as a result of not performing an SG inspection, is the elimination of the need for a plant mid-loop hold for installation of SG nozzle dams. This evolution is performed by personnel in a confined space internal to the SG channel head under a high radiation environment with the plant at a reduced primary water inventory. For SG inspections, there are heavy lifts associated with moving equipment onto the refuel floor, into containment, and to the SG platforms. The primary and secondary manways must also be rigged off and installed back on the RSGs. Personnel performing these activities could potentially be working in a locked high radiation area. Working in the upper internals of the RSGs also requires putting personnel inside a confined space.

While risk is minimized as much as possible through plant processes and procedures, performing 100% SG inspection scope in a 96 EFPM sequential period will reduce the total number of outages that the above associated activities are performed. This will yield a corresponding reduction of personnel dose exposure while improving plant and personnel safety.

3.0 TECHNICAL EVALUATION

3.1 SYSTEM DESCRIPTION

The SQN Unit 1 RSGs have a vertical shell and U-tube evaporator with integral moisture separating equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the SG. The head is divided into inlet and outlet chambers by a vertical divider plate extending from the head to the tubesheet. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel. Details of the SQN Unit 1 RSGs are described in the SQN updated final safety analysis report (UFSAR) Section 5.5.2, “Steam Generator.” Materials of construction for the SQN Unit 1 RSGs are provided in UFSAR Table 5.2.3-1, “Reactor Coolant Pressure Boundary

Materials Class A Primary Components." Materials are selected and fabricated in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Code Sections II and III.

The SQN Unit 1 SGs were replaced during the SQN U1R12 outage in Spring 2003. SQN Unit 1 is a four-loop plant with recirculating Westinghouse Model 57AG RSGs equipped with 4,983 Alloy 690 thermally treated (Alloy 690TT) tubes arranged in a triangular pitch forming a U-tube bundle. The tubes have an outer diameter of 0.75 inches with a 0.043-inch nominal wall thickness. The tube plugging limit at SQN Unit 1 is 15% or 747 tubes per RSG. The tubesheet base metal is clad with Alloy 690 material. The low tube rows were heat treat stress relieved over their entire length following bending. Each tube is hydraulically expanded into the tubesheet and welded to the clad at the primary face of the tubesheet. There are seven advanced tube support grids (ATSG) consisting of a grid of slotted bars, which provide horizontal support to the straight leg of every tube. The tubes are supported in the U-bend region by ventilated flat bar support trees with varying numbers of vertical and diagonal support elements depending on the tube location.

Figure 1 provides a general arrangement view of the SQN Unit 1 RSG. The Model 57AG RSG designed by Westinghouse and manufactured by Doosan Heavy Industries represent an advanced second-generation design that is expected to provide enhanced margin against known SG tubing and secondary side component degradation mechanisms. There have been no changes to the design and operating parameters, such as plant uprate or physical modification, of the SQN Unit 1 RSG since installation. The SQN Unit 1 RSGs are a similar design to the SQN Unit 2 RSGs.

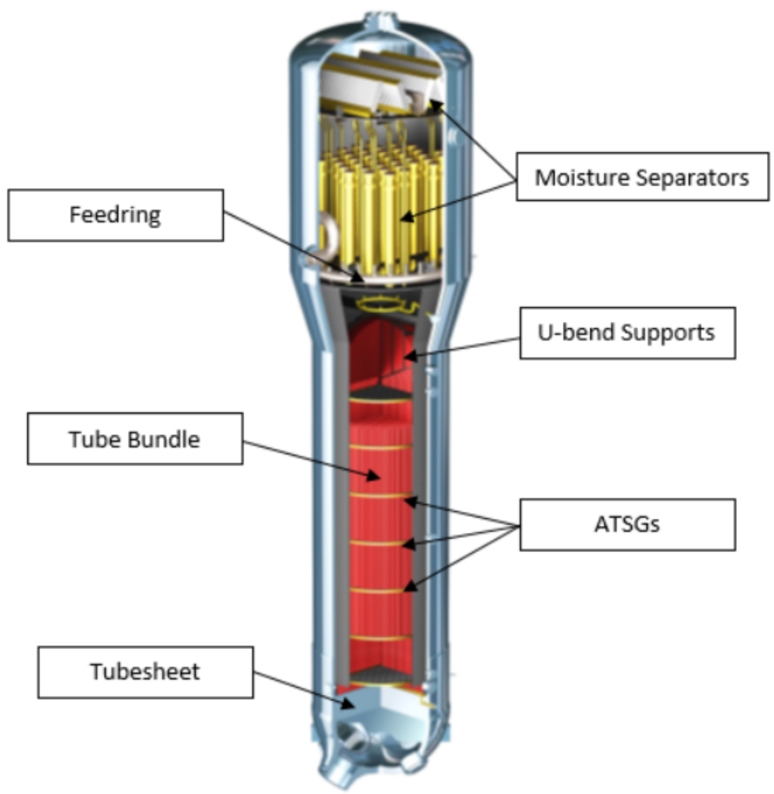

Figure 1: SQN Unit 1 RSG - Westinghouse Model 57AG

3.2 TECHNICAL ANALYSIS

The SG tubes in pressurized water reactors have several important safety functions. The SG tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. As part of the RCPB, the SG tubes are unique in that they act as a heat transfer surface between the primary and secondary systems to remove heat from the primary system. In addition, the SG tubes isolate the radioactive fission products in the primary coolant from the secondary system.

The SG tube rupture (SGTR) accident is the limiting design basis event for SG. The analysis of an SGTR event assumes a bounding primary to secondary leakage rate equal to the operational leakage rate TS limit, plus the leakage rate from a double-ended rupture of a single tube. The accident analysis for an SGTR assumes the contaminated secondary fluid is only briefly released to the atmosphere via SG atmospheric relief valves and safety valves. The analysis for design basis accidents and transients other than an SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture). In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary leakage from all SG or is assumed to increase to the TS limit because of accident-induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level is assumed equal to the TS limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel.

SG tube integrity is necessary to ensure the tubes are capable of performing their intended safety functions. Concerns relating to the integrity of the tubing stem from the fact that the SG tubing is subject to a variety of degradation mechanisms. SG tubes have experienced tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

The industry, working through the Electric Power Research Institute (EPRI) Steam Generator Management Program (SGMP), has implemented a generic approach to managing SG performance referred to as "Steam Generator Degradation Specific Management" (SGDSM). The overall program is described in Nuclear Energy Institute (NEI) 97-06, "Steam Generator Program Guidelines," which is supported by EPRI guidelines, including:

- PWR Steam Generator Examination Guidelines
- Steam Generator Integrity Assessment Guidelines
- Steam Generator In-Situ Pressure Test Guidelines
- PWR Primary-to-Secondary Leak Guidelines
- PWR Primary Water Chemistry Guidelines
- PWR Secondary Water Chemistry Guidelines

NEI 97-06 and the EPRI Guidelines define a comprehensive, performance-based approach to managing SG performance.

3.2.1 Background and Introduction

The design of the original SQN Unit 1 SG had Alloy 600 mill annealed (Alloy 600MA) tube material. Alloy 600MA is susceptible to in-service stress corrosion cracking degradation under the operating conditions of most commercial nuclear sites. This form of degradation led to plugging significant numbers of tubes and shortening the useful life of the SQN Unit 1 original SG to the point of early replacement, which occurred in Spring 2003.

With the operating experience of Alloy 600MA SG tube material recognized throughout the industry, Alloy 690TT has emerged as the tube material of choice for both new and replacement pressurized water reactor SG. This tube material has been found through laboratory studies and operating experience to have significantly greater resistance to corrosion induced degradation. The first commercial nuclear SGs with Alloy 690TT tubing were put into service in 1989. The Alloy 690TT tube material now has nearly 30 years of operating service experience domestically. There are approximately 50 nuclear units operated within the United States with Alloy 690TT SG tube material and this population has an average operating age of about 17 years. The predominant degradation mechanism for SG with Alloy 690TT tubing, including the SQN Unit 1 RSGs, has been volumetric wear due to interaction with tube support structures. There have been no reported indications of stress corrosion cracking degradation in any Alloy 690TT tube to date.

During the SQN RSG fabrication, 18 tubes were preventatively plugged due to broken U-bend support lock bars at eight different locations on the edge of the tube bundle. Loads resulting from vessel rotation during fabrication caused the lock bars to break or crack. Associated loose parts were removed and the lock bars themselves were stabilized by welding. Two additional tubes were plugged during the preservice inspection (one due to wear near the lock bar repair activities and one due to a restricted tube) for a total of 20 plugged tubes. No operational wear associated with this fabrication issue has been observed.

The RSGs at SQN have undergone a pre-service inspection (PSI) and four inservice inspections (ISI), the results of which are described in Section 3.2.3 to this enclosure. There are currently two existing in-service tube degradation mechanisms in the RSGs (i.e., wear at the tube bundle U-bend support structures and tube wear at the ATSGs). Fourteen tubes have been plugged to date due to these in-service tube degradation mechanisms since initial service in 2003. The remainder of tube plugging occurred during the pre-service inspections and fabrication for a total of 34 plugged tubes.

3.2.2 Technical Specification Sequential Periods

The current SQN TS reflect TSTF-510, Revision 2, “Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection.” For ISI of SG with Alloy 690TT tubing, in accordance with TSTF-510, Revision 2, the SQN TS permits an initial sequential period of 144 EFPM for 100% inspection of the SG tubes with techniques qualified for detecting existing and potential degradation. The accrual of service for this requirement begins after the first ISI and does not include the PSI. Under the current TS requirements, the lengths of the sequential periods are 144 EFPM (first inspection period), 120 EFPM (second inspection period), 96 EFPM (third inspection period), and 72 EFPM (fourth and subsequent inspection periods). TVA completed the first inspection period for the SQN Unit 1 RSGs in Fall 2016, the results of which are

described in Section 3.2.3 to this enclosure. SQN is currently in the second sequential inspection period.

The percentage of SG tubes that must be inspected is dependent on the number of scheduled inspections over the sequential period. Inspections must also be planned such that 100% of the tubing has been inspected by the end of the sequential period. If an active degradation mechanism associated with cracking is present, then the affected and potentially affected SG shall be inspected at the subsequent refueling outage.

Table 1 indicates the planned SG inspection schedule for the current SQN Unit 1 TS intervals and the proposed intervals. As shown in Table 1, 100% of the tubes will be inspected in each 96 EFPM sequential period. The SG OA performed based on the results of the most recent U1R21 inspection supports the inspection interval under the proposed license amendment (see Section 3.2.3 to this enclosure).

Table 1 SQN Unit 1 Replacement SG Sequential Periods

SGs Replaced 1R12 S-03	1R13 F-04	1R14 S-06	1R15 F-07	1R16 S-09	1R17 F-10	1R18 S-12	1R19 S-13	1R20 S-15	1R21 F-16	1R22 S-18	1R23 F-19	1R24 S-21	1R25 F-22	1R26 S-24	1R27 F-25	1R28 S-27	1R29 F-28
SG EFPY Cumulative	1.3	2.7	4.1	5.4	6.8	8	9.5	11	12.4	13.7	14.9	16.3 est.	17.7 est	19.1 est.	20.5 est	21.9 est.	23.3 est.
EFPM Within Sequential Period	0	16.8	33.6	49.2	66	80.4	98.4	116.4	133.2	4.8	19.2	36 est.	52.8 est.	69.6 est.	86.4 est	103.2	120
TS Sequential Period	1st ISI	144 EFPM Sequential Period								120 EFPM Sequential Period							
Bobbin Base Scope[1]	100% All SGs	No ECT	54% All SGs	No ECT	No ECT	46% All SGs	No ECT	No ECT	100% All SGs[3]	No ECT	No ECT	50% All SGs[2]	No ECT	No ECT	50% All SGs[2]	No ECT	No ECT
EFPM Within Proposed Sequential Period										4.8	19.2	36.0 est.	52.8 est.	69.6 est.	86.4 est.	7.2 est.	24.0 est.
Proposed TS Sequential Period										1st 96 EFPM Sequential Period							
Bobbin Base Scope Under Proposed Amendment[4] ->										No ECT	No ECT	No ECT	No ECT	100% All SGs[3]	No ECT	No ECT	No ECT

Notes

1. The bobbin base scope is accompanied by additional special interest and diagnostic exams using RPC and Array probes.
2. 50% is the TS minimum required inspection scope determined by dividing 100% by the number of scheduled inspections within the period.
3. The SQN U1R21 inspection consisted of a 100% combination bobbin and array coil inspection of all tubes full length with the exception of the U-bend sections of tube Rows 1 through 4, which were inspected with a singular bobbin probe due to dimensional constraints. This is the planned scope for all scheduled inspections under the proposed amendment.
4. The schedule under the proposed amendment revises the allowable inspection interval for each SG to at least every 96 EFPM.

Abbreviations

ECT - Eddy Current
EFPY - Effective Full Power Years
EFPM - Effective Full Power Months
est. - estimated
F - Fall Outage and Year
ISI - In-Service Inspection
S- Spring Outage and Year
SG - Steam Generator
TS - Technical Specification

Table 1 SQN Unit 1 Replacement SG Sequential Periods (continued)

	1R30 S-30	1R31 F-31	1R32 S-33	1R33 F-34	1R34 S-36	1R35 F-37	1R36 S-39	1R37 F-40	
SG EFPY Cumulative	24.7 est.	26.1 est.	27.5 est.	28.9 est.	30.3 est.	31.7 est.	33.1 est.	34.5 est.	**End of SQN Unit 1 License**
EFPM Within Sequential Period	16.3 est.	33.1 est.	49.9 est.	66.7 est.	83.5 est.	4.3 est.	21.1 est.	37.9 est.	
TS Sequential Period	96 EFPM Sequential Period					72 EFPM Sequential Period			
Bobbin Base Scope[1]	50% All SGs[2]	No ECT	No ECT	50% All SGs[2]	No ECT	No ECT	100% All SGs[2]	No ECT	
EFPM Within Proposed Sequential Period	40.8 est.	57.6 est.	74.4 est.	91.2 est.	12.0 est.	28.8 est.	45.6 est.	62.4 est.	
Proposed TS Sequential Period	2nd 96 EFPM Sequential Period				3rd 96 EFPM Sequential Period				
Bobbin Base Scope Under Proposed Amendment[4] ->	No ECT	100% All SGs[3]	No ECT	No ECT	No ECT	No ECT	100% All SGs[3]	No ECT	

Notes

1. The bobbin base scope is accompanied by additional special interest and diagnostic exams using RPC and Array probes.
2. 50% is the TS minimum required inspection scope determined by dividing 100% by the number of scheduled inspections within the period.
3. The SQN U1R21 inspection consisted of a 100% combination bobbin and array coil inspection of all tubes full length with the exception of the U-bend sections of tube Rows 1 through 4, which were inspected with a singular bobbin probe due to dimensional constraints. This is the planned scope for all scheduled inspections under the proposed amendment.
4. The schedule under the proposed amendment revises the allowable inspection interval for each SG to at least every 96 EFPM.

3.2.3 SQN Unit 1 Steam Generator Inspection, Degradation, and Plugging History

The SQN Unit 1 RSGs have undergone a pre-service eddy current inspection and four ISIs. Table 1 shows the actual bobbin probe inspection scope for each of the SQN Unit 1 refueling outages U1R13 through U1R21, and the plan of inspection through the remaining renewed license of the plant. The U1R13, U1R15, and U1R18 bobbin inspection programs at SQN were accompanied by rotating pancake coil (RPC) probe examinations in order to satisfy the TS requirement of sampling for potential degradation with a qualified technique within the sequential period. The ISI during SQN U1R21 consisted of a 100% inspection with a combination bobbin and array coil probe over the full length of the tubes with the exception of the low row U-bends. The low rows were inspected with a singular bobbin probe due to dimensional restrictions through the bend region.

Pre-Service Inspection

A PSI eddy current inspection took place prior to initial service of the SQN Unit 1 RSGs. The scope of the PSI eddy current inspection consisted of 100% full-length bobbin coil examination in the four RSGs. The small radius U-bend locations were inspected 100% with RPC probes to complete the full tube length examinations in the low row tubes. Further, RPC examinations were also performed in 100% of the top of the tubesheet expansion transitions on the hot leg side. In addition a special interest RPC program was performed, as needed, to characterize bobbin indications that could not be resolved.

Tubes in the RSGs were repaired by plugging and stabilizing during the PSI due to a fabrication non-conformance. Eight locations of lock bars on the upper tube bundle supports were found to be cracked or broken near the ends. As a result, some peripheral tubes in the RSGs could not be proven to be fully supported as designed. Portions of the lock bars also had to be stabilized by welding to mitigate the potential for creation of loose parts. One tube was identified with actual tube wear degradation in the immediate vicinity of the lock bar repair work. Therefore, this tube was also preventively stabilized and plugged. Twenty tubes were plugged prior to initial service of the SQN Unit 1 RSGs.

SQN U1R13 First In-Service Inspection - Fall 2004

All tubes were inspected full length with the bobbin probe during the SQN U1R13 first ISI of the RSGs. The inspections also included a special interest RPC program performed of signals not able to be resolved by bobbin data review. During the U1R13 inspection, there were 11 tubes identified with tube wear in the region of the second and fourth vertical strap tube supports (VS2 and VS4). The largest indication detected was measured to be 17% through-wall (%TW) in depth. The tube wear indications detected during the U1R13 inspection could have remained in-service with no challenge to tube integrity during the inspection interval. However, TVA preventively plugged the 11 tubes with detected wear indications. Top-of-tubesheet sludge lancing and foreign object search and retrieval (FOSAR) was also performed during U1R13 in the four RSGs. The foreign material identified was removed from the SG secondary side.

Further details of the SQN U1R13 SG ISI results are provided in Reference 1.

SQN U1R15 Second In-Service Inspection - Fall 2007

The base scope bobbin inspection for the SQN U1R15 inspection was 54% of the unplugged tubes in the RSGs. The inspections included a special interest RPC program performed of signals that could not be resolved by bobbin data review. During the U1R15 inspection, there were 47 tubes identified with tube wear at the U-bend support structure intersections. The largest indication detected was measured to be 16%TW in depth. The tube wear indications remained in-service with no challenge to tube integrity during the inspection interval projected by the OA. No SG tube plugging occurred during the SQN U1R15 inspections. Sludge lancing and FOSAR was also performed during U1R15 in the RSGs. The foreign material with significance relative to maintenance of tube integrity was removed and no associated wear due to foreign objects was observed visually or by eddy current. No indications of possible loose parts (PLPs) were identified by the eddy current program in SQN U1R15.

Further details of the SQN U1R15 SG ISI are provided in References 2 and 3.

SQN U1R18 Third In-Service Inspection - Spring 2012

The base scope bobbin inspection for the SQN U1R18 inspection was 46% of the open tubes in the RSGs. The bobbin inspection included the tubes with prior indications of degradation and the tubes not inspected during the previous ISI. Further, an inspection program with the combination bobbin and array coil probe inspected regions considered most susceptible to foreign object wear near the top of tubesheet on both the hot and cold leg side. A special interest RPC program was performed of signals that could not be resolved by bobbin or array coil data review. Volumetric wear at tube U-bend support structures was detected while tube wear at ATSG was detected for the first time during SQN U1R18. Two tubes were preventatively plugged and one was stabilized. The tubes plugged were those with the two deepest wear indications. One tube had a 38%TW wear indication and the other tube had an indication of 29%TW, both at a U-bend support intersection. No tubes were plugged due to wear at an ATSG during U1R18.

In addition to the eddy current examinations, visual inspections were also performed from the SG primary and secondary sides. The primary side visual inspections included the previously installed tube plugs, the channel head bowl cladding, and the divider plate. Secondary side FOSAR visual inspections were performed at the top of tubesheet for the detection of foreign objects. No wear attributable to foreign objects were detected visually or by eddy current. Inspection of the upper steam drum internals were also performed visually in the RSGs during U1R18 and no degradation was identified.

Further details of the SQN U1R18 SG ISI are provided in References 4 and 5.

SQN U1R21 In-Service Inspection - Fall 2016

The U1R21 outage included combination bobbin and array coil inspection of 100% of the in-service tubes full length except for tubes in Rows 1 through 4. Tube Rows 1 through 4 were inspected to the first support with the combination bobbin and array coil from both the hot leg tube end (HTE) and the cold leg tube end (CTE). The remainder of the tube length in Rows 1 through 4 was inspected with a singular bobbin probe due to dimensional clearance restrictions in the U-bend region.

In addition to the eddy current inspections, visual inspections were also performed on both the primary and secondary sides. Primary side visual inspections included the previously installed tube plugs, the channel head bowl cladding, and the divider plate. Secondary side visual inspections were performed at the top of the tubesheet for the detection of foreign objects, assessment of hard deposit buildup in the tube bundle interior tubesheet kidney region and for determining the effectiveness of the tubesheet cleaning performed in the RSGs.

Prior to the secondary side foreign object search and retrieval (FOSAR) inspections, sludge, scale, foreign objects, and other deposit accumulations at the top of the tubesheet were removed as part of the top of tubesheet water lancing process. The secondary side FOSAR inspections performed in the RSGs included visual examination of tube bundle periphery tubes from the hot leg and cold leg annulus and center no tube lane. The foreign objects remaining were small pieces of gasket, wires, bristles, and graphite. Any foreign objects not able to be retrieved were characterized and an analysis performed to demonstrate acceptability of continued operation without exceeding the performance criteria.

The only degradation mechanism detected during the U1R1 inspection was volumetric wear at the tube U-bend support structures and the ATSG. The maximum depth tube wear indication detected was 36%TW at a U-bend support structure, which was the only tube plugged during U1R21. The maximum depth tube wear indication located at an ATSG was 22%TW, which remained in service.

Further details of the SQN U1R21 SG ISI results are provided in Reference 6.

3.2.4 Trending of Existing Degradation Mechanisms

Based on ISI results of the eddy current inspection, the only existing tube degradation mechanisms affecting the RSGs are wear at U-bend supports and wear at the ATSGs. Wear at U-bend supports has been the predominant mechanism, whereas wear at ATSG has only affected a small number of tubes at shallow through-wall depths. Trends in existing degradation have been observed with four ISIs over sixteen years of SQN Unit 1 operation with the RSGs.

Figure 2 presents the total numbers of tube wear indications for each mechanism over each of the four ISIs along with the maximum detected %TW depths. Also indicated in Figure 2 is the number of tubes plugged for each mechanism at each inspection. It is important to recognize the difference in number of refueling outages between inspections, inspection scopes performed, and techniques applied as noted in Figure 2. For example, there is one refueling outage, or two cycles, between the first two inspections and two refueling outages, or three cycles, between the others.

Although the U1R21 inspection has the largest number of U-bend wear indications detected, it is also the only inspection where a 100% inspection was performed with the combination bobbin and array coil probe. Degradation was reported by the eddy current analysts with either coil during the U1R21 inspection and the array coil has enhanced detection capabilities for volumetric wear indications as compared to the bobbin coil. Therefore, the U1R21 inspection results are considered the most accurate and fully representative picture of the degradation conditions in the SQN Unit 1 RSGs.

Figure 3 shows the population versus depth distributions of wear at U-bend supports for every inspection of the SQN Unit 1 RSGs. Tubes with degradation that have been plugged are indicated with a solid black circle surrounding the data point. Also shown is a vertical line representing the TS plugging limit of 40% TW for the SQN Unit 1 RSGs tubing. The 40%TW plugging limit can be used to represent a conservative SG tube structural and leakage integrity limit. These limits are typically about 10 to 20%TW higher than the TS plugging limit for SQN Unit 1. As shown in Figure 3, there have been no tube wear indications at SQN Unit 1 to date that have come near the associated structural and leakage integrity performance criteria nor the 40%TW tube plugging limit.

There are 19,932 tubes total between the four SQN Unit 1 RSGs and 34 of them are plugged. Table 2 shows the count and percentage of tubes plugged in the RSG at SQN Unit 1. There were 20 tubes plugged prior to initial service of the RSG. There have been 14 tubes preventively plugged in-service due wear at U-bend support structures, and none plugged due to wear at the ATSGs.

Table 2 SQN Unit 1 RSG Tube Plugging

Degradation Mechanism	SG1	SG2	SG3	SG4	All SG
Pre-Service	4	6	5	5	20
U-bend Support Structure	12	0	2	0	14
Horizontal Grid Wear	0	0	0	0	0
Total	16	6	7	5	34
Percentage	0.32%	0.12%	0.14%	0.10%	0.17%

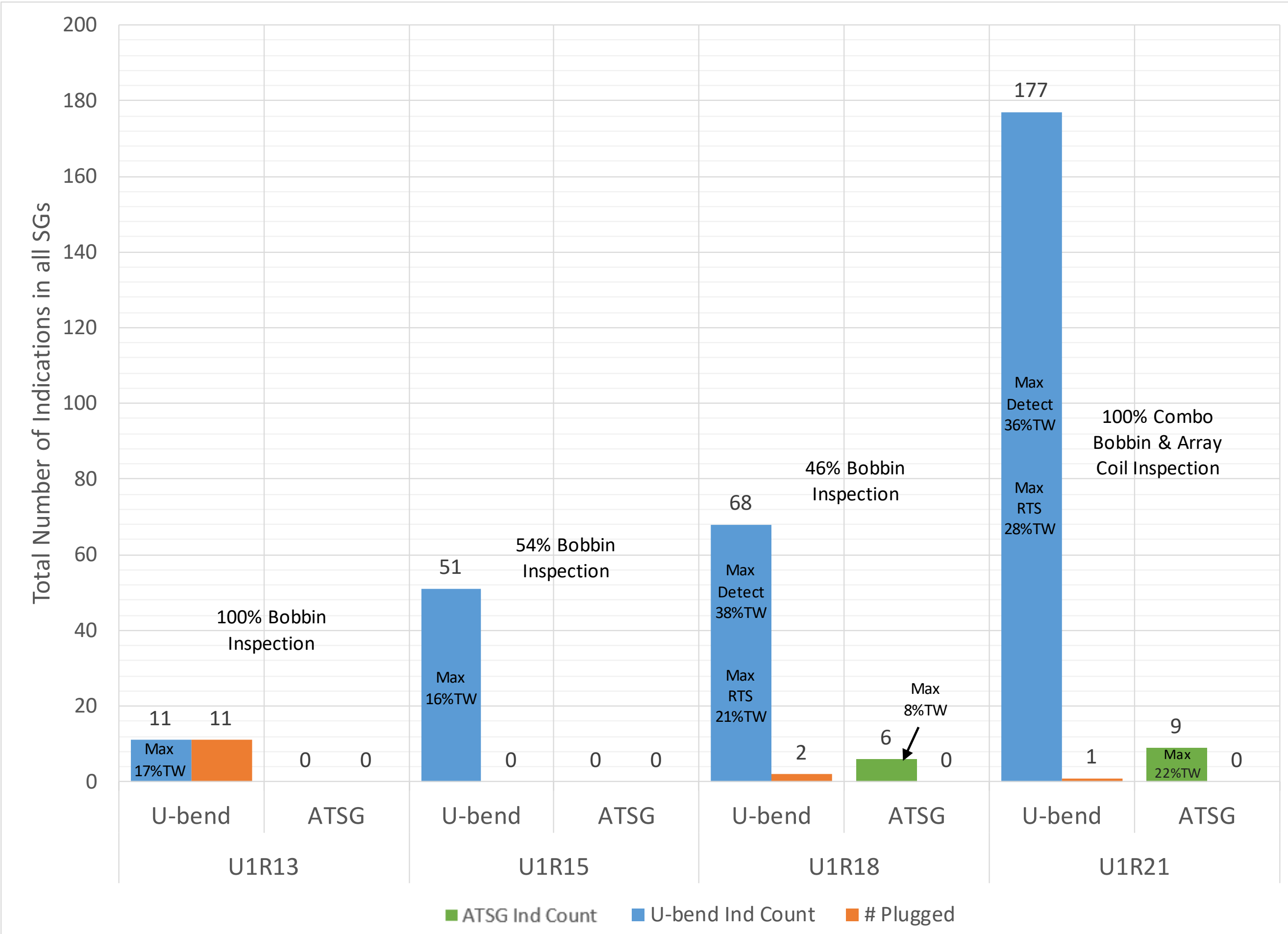

Figure 2 SQN Unit 1 RSG Support Wear Indications Summary

Enclosure

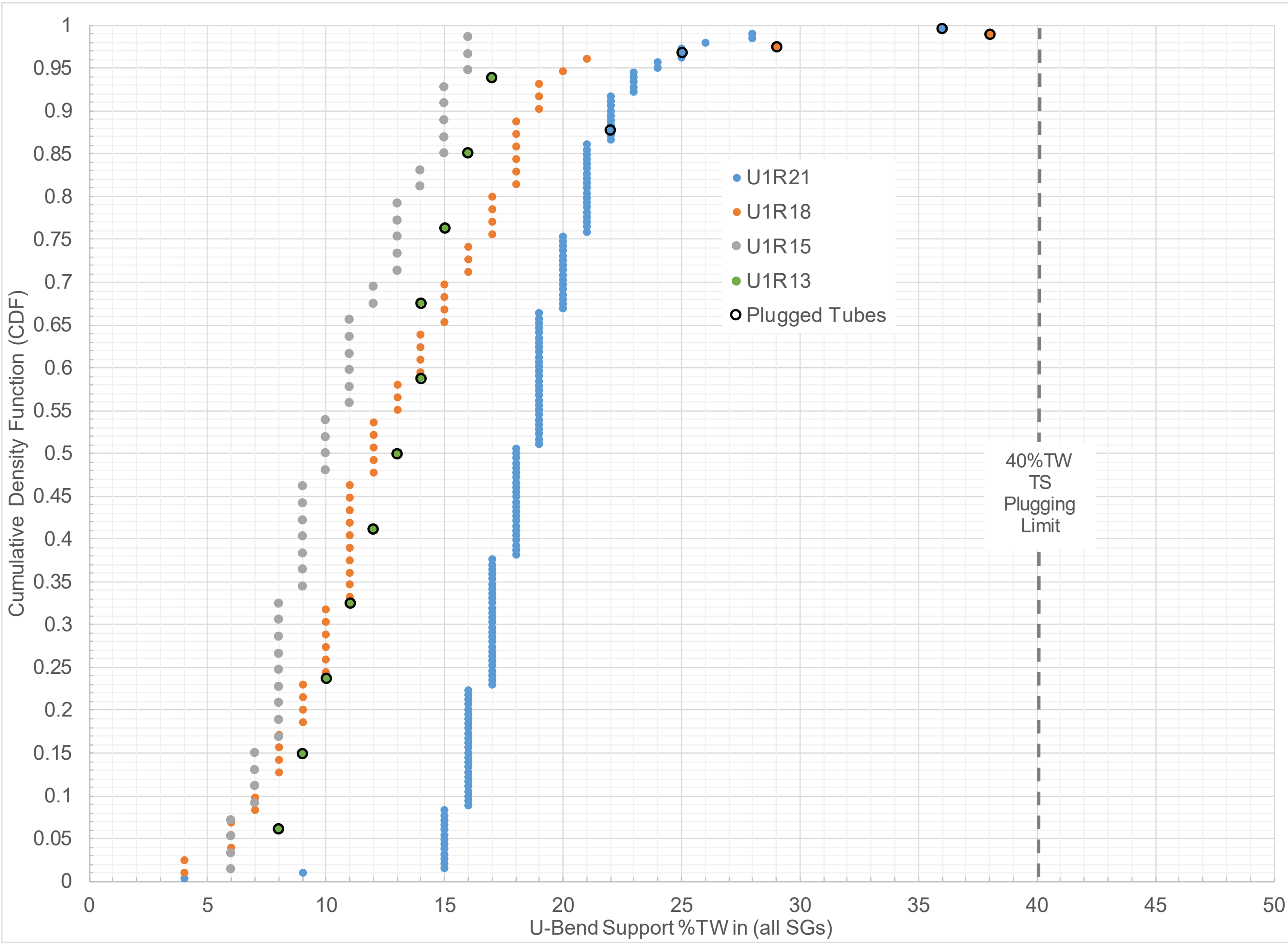

Figure 3 SQN Unit 1 RSG Distribution of U-bend Support Wear Depths

3.2.5 SQN Unit 1 Steam Generator Secondary Side Conditions

Secondary Side Tubesheet Cleanings

SQN has performed a top of tubesheet cleaning coincident with every ISI of the Unit 1 RSGs since their installation. Most recently, a top of tubesheet deposit cleaning process was performed in the four RSGs during SQN U1R21. There are two main purposes of performing the cleaning process. The first is to remove hardened deposits that tend to form at the top of the tubesheet, and the second is to force and filter out any loose parts or foreign objects that have migrated to the SG secondary side during operation. The cumulative mass of deposit material and debris removed by the top of tubesheet cleaning process is summarized in Table 3-3 below.

Table 3 SQN U1R21 RSG Deposit Removal

SG 1	24.0 lbs
SG 2	36.5 lbs
SG 3	24.5 lbs
SG 4	32.5 lbs
All SG	117.5 lbs

Periodic views of the cleaning system's in-line coarse grit tank screen filter were performed throughout the U1R21 RSGs tubesheet cleaning process. This confirmed that the process was successful at removing small numbers of foreign objects and material from the RSG secondary side in addition to the hardened sludge deposits. Post-outage chemistry laboratory testing of the sludge deposit samples indicates iron to be the main elemental constituent. The percentage of iron content was within the typical industry range.

Regarding deposit buildup trending, the results of both the low frequency eddy current and secondary side top of tubesheet visual inspections indicate the presence of a small kidney region of deposit buildup near the center of the tube bundle. Tubesheet sludge pile depths from U1R21 were measured by eddy current to have a maximum depth of two inches and cover a surface area that spans approximately 30 tubes. This region of hardened deposit has been trended between inspections both visually and by eddy current and not found to be growing unexpectedly. Further, the total of mass deposit removal from the SQN U1R18 SG tubesheet cleanings was 84.5 lbs. Therefore, the deposit removal trends at SQN Unit 1 are within an expected trend over time.

Foreign Object Inspection Results Summary

Although foreign objects have been observed in the SQN Unit 1 RSGs at previous inspections, no tube degradation associated with the presence of these objects has been detected to date. Typical foreign objects identified at SQN Unit 1 have been limited to pieces of flexitallic gasket material, small wires, bristles, and sludge rocks. The array probe was utilized to aid in the detection of foreign objects and foreign object wear during the most recent U1R21 eddy current inspection. During the SQN U1R21 eddy current inspections there were three signals corresponding to a PLP indication located coincident with the top of the tubesheet. There was no tube wall degradation detected by eddy current coincident with these PLP indications. The PLP locations were visually inspected from the secondary side and any associated foreign objects or loose parts were either retrieved or evaluated for continued operation over the SG inspection

interval. Additional visual inspections performed during SQN U1R21 from the SG secondary side identified foreign objects such as bristles, gasket, and sludge rocks. All foreign objects identified during U1R21 measured 1.5 inches or less and the majority was less than 0.75 inch. Although many of these foreign objects were removed from the RSGs, not all of them were retrieved.

The OA performed following SQN U1R21 considered the potential effects of the foreign objects remaining in the SG secondary side. The tube wear rate analysis performed in support of the OA, established that at least six fuel cycles or nine EFPY of operating time would accrue before the identified objects with the greatest potential to cause actual tube wear degradation could potentially exceed the tube integrity performance criteria. The assumed flaw lengths that would be associated with the dimensions of the enveloping foreign objects are less than those applied in the tube wear rate analysis. Therefore, the results of the tube foreign object wear rate analysis are considered conservative.

Upper Internals Inspections

The most recent secondary side inspection of the SQN Unit 1 RSG upper internals occurred during the U1R18 refueling outage. Secondary side visual inspections were performed of the four RSGs by access through the secondary manways. All components inspected were found to be structurally sound. Steam drum inspection areas included the steam separator areas, upper dryer banks, drains, the feedring area with associated supports, feedring spray nozzles, the marmon clamps on the lower hatch to the tube bundle, and the various accessible instrument taps. The only anomalous condition was a small piece of a screen type material lodged in one of the feedwater ring spray can nozzles, which was removed from the RSG.

The design of the SQN Unit 1 feedring is such that the intrusion of significant foreign objects or loose parts into the SG secondary side is mitigated. The main feedwater flow into the RSG travels through spray can nozzles mounted to the top of the feedring. The spray can style nozzles, which distribute the feedwater around the circumference of the feedring, have many small diameter holes drilled into them. These holes serve as a screen and acts to trap foreign objects or loose parts internal to the feedring. Trapped foreign material collected inside the feedring then cannot travel to an area where it can cause tube degradation. Access to the internal of the feedring for periodic cleaning is then provided through an individual threaded removable spray can nozzle although this was not considered necessary during U1R18 based on the limited foreign material observed.

3.2.6 Secondary Chemistry Control

The overall objective of the SQN Unit 1 secondary chemistry strategy is to optimize chemistry with consideration of the relative risks and expected benefits of different chemistry control approaches. This approach was developed based upon the SQN secondary cycle design and metallurgy. The SQN Chemistry Program is designed to preserve the SGs and secondary system integrity.

The secondary chemistry plan is continuously reviewed and updated as the secondary chemistry program is optimized. Secondary chemistry specifications include the required secondary chemistry parameters, limits, and sampling frequencies, which are based on the EPRI PWR Secondary Water Chemistry Guidelines. SQN Unit 1 has not

experienced any corrosion related degradation mechanism; therefore, corrosion degradation mechanisms are not considered potential mechanisms for the SQN Unit 1 RSGs.

SG control parameters are consistently kept below limits. SQN injects hydrazine as an oxygen scavenger to ensure low oxygenated water is fed to the RSGs. Hydrazine breaks down to ammonia at elevated temperatures, which increases the pH of water entering the SG. Sequoyah injects ethanolamine (ETA) at a target value of 3.5 parts per million (ppm) to establish an elevated pH in wet steam areas on the secondary side. This chemistry regime has allowed feedwater iron to routinely remain less than one parts per billion (ppb) while online.

The RSGs are placed in chemical wet lay-up with ammonia, carbohydrazide, and dimethylamine (DMA) once conditions are allowed shortly after shutdown. SQN utilizes full-flow condensate polishers, high quality makeup deionized water (DI) water, and elevated SG blowdown flow during startups from refueling outages to minimize contaminants sent to the RSGs.

An evaluation of the SQN Unit 1 RSG secondary side contaminant hideout return is performed each outage. These evaluations assess the tendency for SG tubing and tube support structure corrosion. These assessments are also used to consistently evaluate the effectiveness of the secondary water chemistry control program.

3.2.7 Discussion of Growth Rates, OA Methods, Projections, and Results

Degradation Growth Rates

The SQN Unit 1 RSGs have been inspected in-service by eddy current techniques four times over an operating period of greater than 14.9 EFPY since installation. Every tube in each RSG has been tested full length at least three times in this operating span with techniques qualified for detection of all existing and potential degradation mechanisms. The nature of the RSG degradation growth rates are relatively predictable based on this operating experience.

Figure 4 shows the growth rate distributions for the SQN Unit 1 RSG inspections for the U1R18 and U1R21 inspections. The degradation growth rates in this figure have been normalized to a %TW/EFPY basis. The indications of tube wear degradation were plugged at the U1R13 inspection eliminating growth rate data on existing wear indications at the subsequent inspection. Fifty-one low level U-bend support wear indications were detected in 47 tubes at the U1R15 inspection after a two-cycle interval. Therefore, mature U-bend support wear growth rate data has been achieved at both the U1R18 and U1R21 inspections. However, only one distribution of degradation growth is available for volumetric wear at the horizontal ATSG given that the mechanism was only first detected at the U1R18 inspection. The observed behavior U-bend support wear growth rates are considered encompassing of that for tube wear occurring at intersections with the ATSG.

The largest wear indication at U-bend supports remaining in service following U1R21 is 28%TW and for wear at the ATSGs is 22%TW. The largest individual growth rate observed in any degradation mechanism to date has been 5.4%TW/EFPY. The population of U-bend support wear growth rates had a 95th percentile of 3.7%TW/EFPY during the U1R21 inspection. The in-service plugging performed to date has been for

indications of tube wear at U-bend supports. Plugging strategies have been proactive for the purposes of providing both margin and conservatism in the OA process and not based on degradation growth rates, which would cause an inspection interval of less than the current TS limit of not more than three refueling outages.

Further, there have been two 100% inspections performed of the SQN Unit 2 RSGs. The SQN Unit 2 RSG degradation growth rates observed to date are comparable, if not improved, from the SQN Unit 1 degradation experience after similar operating EFPYs. As a result, reasonably accurate and conservative OA projection results of existing degradation mechanisms are anticipated over the proposed revised inspection intervals.

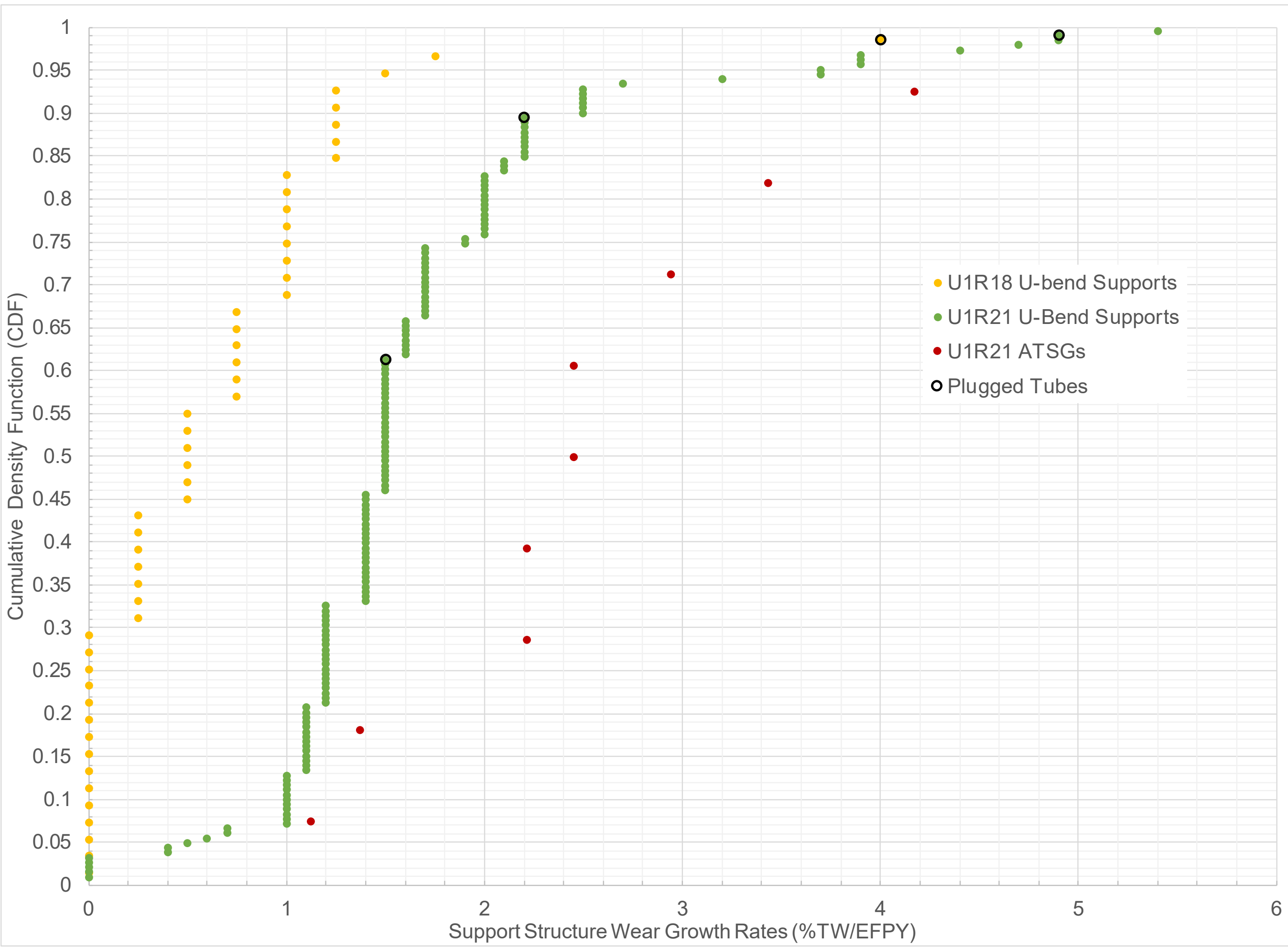

Figure 4 SQN Unit 1 RSG Distribution of Support Wear Growth Rates

Comparison of Historical OA Projections to As-Found Indications

The growth rates of existing degradation mechanisms are used to project future inspection results in the OA. The method of projection can involve varying levels of conservatisms based on the available inspection data and history of degradation growth rates. Using the arithmetic methods is the most conservative OA projection approach as described in EPRI guidelines. As degradation mechanisms mature, statistical methods such as Monte Carlo simulations become a viable option based on the increased populations of available growth rate data points.

Table 4 shows the different OA strategies that have been applied during the operation of SQN Unit 1. In early SQN Unit 1 inspections, acceptability over the three-cycle inspection interval was demonstrated through the arithmetic projection method. The results of this simple and conservative method were such that there was no need to apply more complex OA projection methods. Given the increased number of degradation growth rate data points available, Monte Carlo simulations have been applied at the most recent U1R21 inspection in order to make OA degradation projections. The methods used are described in the EPRI Guidelines and justify the RSG inspection interval.

Table 4 further provides the actual SQN Unit 1 inspection results for the maximum %TW detected and the maximum %TW indication left remaining in service following the performance of tube plugging at each inspection. Also shown is the OA projected maximum %TW that could be encountered at the subsequent SG inspection. The margin to maximum %TW detected was determined by subtracting the maximum detected %TW indication from the OA projected maximum %TW.

Conservative assumptions are inherent in the OAs performed of the SQN Unit 1 RSGs. Examples of the conservatisms applied in the SQN Unit 1 OAs are provided below:

- Tube wear degradation lengths are assumed the full length of the tube support intersections. The actual axial extent of the flaws detected and measured by eddy current have been just a fraction of the support intersection typically at the top or bottom edge. This results in overly conservative tube integrity limits as longer flaws have lower %TW tube integrity limits.
- Each SQN Unit 1 operating cycle is assumed to be 1.5 EFPY. The average operating cycle duration since SG replacement is 1.34 EFPY. Assuming longer duration operating cycles leads to conservative degradation projections.
- The structural integrity performance criteria (SIPC) of three times normal operating pressure differential is conservatively determined. The value applied ignores pressure drops within the system between the measurement point and the secondary side of the tubing. The estimated pressure drop from the RSG normal water level to the steam pressure measurement point is 8.5 psi, which would add about 25.5 psi of conservatism to the SIPC.

Despite the above conservatisms, the SQN Unit 1 OAs have consistently demonstrated margin to the tube integrity limits.

Table 4 provides the OA projected maximum %TW degradation for each of the existing degradation mechanisms at the U1R24 and U1R26 refueling outages. The degradation projections are based on the Monte Carlo statistical method. Acceptable OA

degradation projections are demonstrated at the U1R26 refueling outage, which would be the next SQN Unit 1 RSG inspection based on the proposed TS amendment.

Table 4
Comparison of SQN Unit 1 RSG Inspection Results and OA Projections

		SQN Unit 1 Inspection Results		Operational Assessment Projections		
Outage	**Wear Location**	**Max %TW Detected**	**Max %TW Remaining in Service**	**OA Projected Max %TW**	**Margin to Max %TW Detected**	**OA Method**
U1R13	U-bend	17	0	Note 1		
U1R14	No SG inspection					
U1R15	U-bend	16	16	55	39	Arithmetic
U1R16	No SG inspection					
U1R17						
U1R18	U-bend	38	21	53.7	15.7	Arithmetic
	ATSG	8	8	Note 1		
U1R19	No SG inspection					
U1R20						
U1R21	U-bend	36	28	50.7	14.7	Arithmetic
	ATSG	22	22	50.7	28.7	
U1R22	No SG inspection					
U1R23						
U1R24	No SG inspection planned					
U1R25						
U1R26	U-bend	Note 2		54.4	Note 2	Monte Carlo
	ATSG			53.9		

<u>**Notes**</u>:

1. This was the outage when the degradation mechanism was first detected. OA projections are only performed for mechanisms that are existing at the prior inspection.
2. Inspection data points are pending results of the next SG inspection.

As the current TS limitation is three operating cycles between inspections, previously performed OA projections did not make degradation growth predictions over five operating cycles. However, an assessment of prior ability to support five-cycle operation can be made by comparing the maximum %TW indications remaining in-service between refueling outages. The largest indications remaining in service following the most recent U1R21 inspection for both U-bend and ATSG wear have a %TW depth greater than any other prior refueling outage. Therefore, using the same degradation growth rates applied at U1R21 for a five operating cycle projection would have demonstrated acceptability against the SG performance criteria if performed based on results of the U1R13, U1R15, or U1R18 inspection.

3.2.8 Conclusion

The current TS SG inspection interval requirements were developed when there was uncertainty around the performance of the Alloy 690TT tube material. Significant experience has been gained over the course of 30 years of service of this tube material type. The SQN Unit 1 RSGs are a second-generation evolutionary design, which incorporate industry-operating experience. The RSGs have been inspected in-service by eddy current techniques four separate times over an operating period of greater than

14.9 EFPY since installation. Through these inspections, every tube in each RSG has been tested full length at least three times with techniques qualified for detection of all existing and potential degradation mechanisms.

The SQN RSG degradation mechanisms are well understood and exhibit predictable behavior. As such, the OAs performed to date have been both accurate and appropriately conservative.

TVA considers the proposed TS change to the SG tube inspection frequency to be a more effective and efficient way to collect data on all SG tubes over the 96 EFPM period. Full bundle data collection, or 100% scope, can be achieved in an overall shorter period with no impact to safety or operation. Over the life of the plant, this results in more frequent inspections per tube. This change minimizes person-hours and dose, and reduces risk to the plant and personnel.

4.0 REGULATORY EVALUATION

4.1 APPLICABLE REGULATORY REQUIREMENTS AND CRITERIA

General Design Criteria

SQN Unit 1 was designed to meet the intent of the "Proposed General Design Criteria for Nuclear Power Plant Construction Permits" published in July, 1967. The SQN construction permit was issued in May 1970. The UFSAR, however, addresses the General Design Criteria (GDC) published as Appendix A to 10 CFR 50 in July 1971. Conformance with the GDCs is described in Section 3.1.2 of the UFSAR.

Each criterion listed below is followed by a discussion of the design features and procedures that meet the intent of the criteria. Any exception to the 1971 GDC resulting from the earlier commitments is identified in the discussion of the corresponding criterion.

<u>Criterion 14, "Reactor Coolant Pressure Boundary"</u>

The reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, or rapidly propagating failure, and of gross rupture.

Compliance with GDC 14 is described in Section 3.1.2.2 of the SQN UFSAR.

<u>Criterion 15, "Reactor Coolant System Design"</u>

The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

Compliance with GDC 15 is described in Section 3.1.2.2 of the SQN UFSAR.

<u>Criterion 16, “Containment design”</u>

Reactor containment and associated systems shall be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

Compliance with GDC 16 is described in Section 3.1.2.2 of the SQN UFSAR.

Criterion 30, "Quality of reactor coolant pressure boundary"

Components, which are part of the reactor coolant pressure boundary, shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

Compliance with GDC 30 is described in Section 3.1.2.4 of the SQN UFSAR.

Criterion 31, "Fracture prevention of reactor coolant pressure boundary"

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady state and transient stresses, and (4) size of flaws.

Compliance with GDC 31 is described in Section 3.1.2.4 of the SQN UFSAR.

Criterion 32, "Inspection of reactor coolant pressure boundary"

Components, which are part of the reactor coolant pressure boundary, shall be designed to permit (1) periodic inspection and testing of important areas and features to assess their structural and leaktight integrity, and (2) an appropriate material surveillance program for the reactor pressure vessel.

Compliance with GDC 32 is described in Section 3.1.2.4 of the SQN UFSAR.

4.2 PRECEDENT

While there is no exact precedent for this LAR, precedence does exit for one-time changes to SG inspection frequencies. For example:

- In Reference 7, NRC issued a license amendment for Arkansas Nuclear One, Unit 2, which granted a one-time change to revise the steam generator inservice inspection frequency TS requirements to allow a 40-month inspection interval after one inspection, rather than after two consecutive inspections.
- In Reference 8, NRC issued a license amendment for South Texas Project (STP), Unit 1, which granted a one-time change to extend the steam generator inservice inspection frequency TS requirements from 40 months to 44 months.
- In Reference 9, NRC issued a license amendment for Virgil C. Summer Nuclear Station, Unit No. 1, which granted a one-time change to extend the steam generator inservice inspection frequency TS requirements from 40 months to 58 months.

4.3 SIGNIFICANT HAZARDS CONSIDERATION

Tennessee Valley Authority (TVA) proposes to revise the Sequoyah Nuclear Plant (SQN) Unit 1 Technical Specifications (TS) to allow a change to the steam generator (SG) inspection frequency. The proposed license amendment request (LAR) revises SQN Unit 1 TS 5.5.7, "Steam Generator (SG) Program," and TS 5.6.6, "Steam Generator Tube Inspection Report," to revise the required SG tube inspection frequency from every 72 effective full power months (EFPM) to every 96 EFPM. SQN operating experience supports this TS revision. No adverse impact to safety and reliability is expected as a result of such a change.

TVA has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. *Does the proposed amendment involve a significant increase in the probability or consequence of an accident previously evaluated?*

   Response: No

   The implementation of the proposed amendment has no significant effect on either the configuration of the plant or the manner in which it is operated based on the improved RSG design and reliability, the inservice inspection (ISI) data, and operational assessments (OAs). The consequences of a hypothetical failure of a tube remain bounded by the current SG tube rupture (SGTR) analysis described in the SQN Updated Final Safety Analysis Report (UFSAR). A main steam line break or feedwater line break will not cause a SGTR because the SG tubes will still meet their structural and leakage performance criteria. Therefore, TVA has concluded that the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated in the SQN UFSAR.

2. *Does the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?*

   Response: No.

   The proposed change will not alter any plant design basis or postulated accidents resulting from potential SG tube degradation. The proposed change does not affect the design of the Replacement SGs (RSGs), the method of operation, nor the reactor coolant chemistry controls. No new equipment is being introduced, and installed equipment is not being operated in a new or different manner. The proposed change will not give rise to new failure modes. In addition, the proposed change does not impact any other plant systems or components. The proposed amendment has no effect on either the configuration of the plant, nor the manner in which it is operated. Therefore, TVA concludes that this proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. *Does the proposed amendment involve a significant reduction in a margin of safety?*

   Response: No.

   The steam generator tubes are an integral part of the reactor coolant pressure boundary and, as such, are relied upon to maintain the primary system pressure and inventory. Revising the SG tube inservice inspection frequency will not alter their function or design. Inspections of the RSGs demonstrate that the RSGs do not have an active damage mechanism. The improved design of the RSGs [Alloy 90 thermally treated (Alloy 690TT) tubes], the ISI data and OAs also provide reasonable assurance that significant tube degradation is not likely to occur. Therefore, TVA concludes that this proposed change does not involve a significant reduction in a margin of safety.

Based on the above, TVA concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92 (c), and, accordingly, a finding of "no significant hazards consideration" is justified.

4.4 CONCLUSION

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

5.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6.0 REFERENCES

1. TVA letter to NRC, “Sequoyah Nuclear Plant (SQN) - Unit 1 Cycle 13 (U1C13) 12-Month Steam Generator Inspection Report,” dated October 20, 2005 (ML053050386)
2. TVA letter to NRC, “Sequoyah Nuclear Plant (SQN) - Unit 1 Cycle 15 (U1C15) 180-Day Steam Generator (SG) Inspection Report,” dated April 23, 2008 (ML081290185)
3. TVA letter to NRC, “Sequoyah Nuclear Plant (SQN) - Unit 1 Steam Generator Tube Inspection Report Response to Request for Additional Information (RAI),” dated August 15, 2008 (ML082320482)
4. TVA letter to NRC, “Unit 1 Cycle 18 - 180-Day Steam Generator Inspection Report,” dated December 17, 2012 (ML12359A037)
5. NRR E-mail Capture - “RE: Sequoyah Unit 1 2012 SG ISI Report (TAC MF0387)”, dated May 13, 2013 (ML13235A138)
6. TVA letter to NRC, “Unit 1 Cycle 21 - 180-Day Steam Generator Tube Inspection Report,” dated February 13, 2017 (ML17045A145)
7. NRC letter to Entergy Operations, Inc., “Arkansas Nuclear One, Unit No. 2 - Issuance of Amendment Re: One-Time Change of Steam Generator Tube Inspection Frequency (TAC No. MB6808),” dated May 28, 2003 (ML031490475)
8. NRC letter to STP Nuclear Operating Company, “South Texas Project, Unit 1 - Issuance of Amendment Re: Onetime Extension to Steam Generator Inservice Inspection Frequency (TAC No. MC1046),” dated June 8, 2004 (ML041610073)
9. NRC letter to South Carolina Electric & Gas Company, “Virgil C. Summer Nuclear Station, Unit No. 1 - Issuance of Amendment Re: One-Time Extension of the Steam Generator Inspection Frequency (TAC No. MB7312),” dated October 29, 2003 (ML033020450)

Enclosure

Attachment 1

Proposed TS Changes (Mark-Ups) for SQN Unit 1

5.5 Programs and Manuals

5.5.7 Steam Generator (SG) Program (continued)

2. Accident induced leakage performance 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.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube plugging criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube plugging criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

2. After the first refueling outage following SG installation, inspect each SG at least every ~~72~~96 effective full power months ~~or at least every third refueling outage (whichever results in more frequent inspections)~~. In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a and ~~,~~ b~~, c, and d~~ below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection

5.5 Programs and Manuals

5.5.7 Steam Generator (SG) Program (continued)

period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 144 effective full power months. This constitutes the first inspection period;

~~b)~~ During the next 96~~120~~ effective full power months, inspect 100% of the tubes. This constitutes the second and subsequent inspection periods.

~~c)~~b) ~~During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the third inspection period; and~~

~~d) During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the fourth and subsequent inspection periods.~~

3. If crack indications are found in any SG tube, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

5.6 Reporting Requirements

5.6.6 Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.7, "Steam Generator (SG) Program." The report shall include:

a. The scope of inspections performed on each SG;

b. Active degradation mechanisms found;

c. Nondestructive examination techniques utilized for each degradation mechanism;

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications;

e. Number of tubes plugged during the inspection outage for each active degradation mechanism;

f. Total number and percentage of tubes plugged to date;

g. The results of condition monitoring, including the results of tube pulls and in-situ testing; and

h. The effective plugging percentage for all plugging in each SG.

i. Discuss trending of tube degradation over the inspection interval and provide comparison of the prior operational assessment degradation projections to the as-found condition.

Enclosure

Attachment 2

Proposed TS Changes (Final Typed) for SQN Unit 1

5.5 Programs and Manuals

5.5.7 Steam Generator (SG) Program (continued)

2. Accident induced leakage performance 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.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube plugging criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube plugging criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

2. After the first refueling outage following SG installation, inspect each SG at least every 96 effective full power months. In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a and b below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection

5.5 Programs and Manuals

5.5.7 Steam Generator (SG) Program (continued)

period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 144 effective full power months. This constitutes the first inspection period;

b) During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second and subsequent inspection periods.

3. If crack indications are found in any SG tube, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

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e. Number of tubes plugged during the inspection outage for each active degradation mechanism;

f. Total number and percentage of tubes plugged to date;

g. The results of condition monitoring, including the results of tube pulls and in-situ testing; and

h. The effective plugging percentage for all plugging in each SG.

i. Discuss trending of tube degradation over the inspection interval and provide comparison of the prior operational assessment degradation projections to the as-found condition.