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April 11, 2006

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

SUBJECT: Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC

Oconee Nuclear Station, Units 1, 2, and 3
Docket Nos. 50-269, 50-270, and 50-287

McGuire Nuclear Station, Units 1 and 2
Docket Nos. 50-369 and 50-370

Application for Technical Specification Improvement Regarding
Steam Generator Tube Integrity and Other Administrative Changes

In accordance with the provisions of Section 50.90 of Title 10 of the Code of Federal Regulations (10 CFR), Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC (Duke) is submitting a license amendment request (LAR) for the Facility Operating Licenses (FOL) and Technical Specifications (TS) for Oconee Nuclear Station Units 1, 2, and 3, and McGuire Nuclear Station, Units 1 and 2.

This LAR would revise the TS requirements related to steam generator tube integrity. The changes are consistent with NRC-approved Revision 4 to Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler, TSTF-449, "Steam Generator Tube Integrity." The availability of this TS improvement was announced in the Federal Register on May 6, 2005, (70 FR 24126), as part of the Consolidated Line Item Improvement Process (CLIIP).

Also, this LAR contains proposed changes to the Oconee FOLs that remove conditions that are now outdated and superseded by the CLIIP. Additionally, the proposed changes revise an organizational description in Oconee and McGuire TS 5.2.1 that is solely administrative in nature and unrelated to the CLIIP.

Attachment 1 provides a description and assessment of the proposed amendment.

Attachment 2a provides the existing FOL and TS pages for Oconee Units 1, 2, and 3, marked-up to show the proposed changes.

Attachment 2b provides the existing TS pages for McGuire Units 1 and 2, marked-up to show the proposed changes.

Attachments 3a and 3b (FUTURE), providing revised, clean FOL, TS, and Bases pages for Oconee and McGuire, respectively, will be provided to the NRC at the time of issuance of the approved amendments.

A001

Attachment 4a provides the existing TS Bases pages for Oconee Units 1, 2, and 3, marked-up to show the proposed changes.

Attachment 4b provides the existing TS Bases pages for McGuire Units 1 and 2, marked-up to show the proposed changes.

In accordance with 10 CFR 50.91, a copy of this application, with enclosures, is being provided to the designated official of the State of North Carolina and to the designated official of the State of South Carolina.

Implementation of this proposed change to the Oconee and McGuire Facility Operating Licenses and TS will require revision to the Oconee and McGuire Updated Final Safety Analysis Reports (UFSAR). Necessary UFSAR changes will be submitted in accordance with 10 CFR 50.71(e).

Duke requests NRC approval of this CLIIP item by October 15, 2006, with each station's implementation to take place within 120 days after the completion of the Fall 2006 refueling outages on Oconee Unit 1 and McGuire Unit 2.

In a letter to the NRC dated February 15, 2006, Duke responded to NRC Generic Letter 2006-01 concerning steam generator tube integrity. In the February 15, 2006 letter, Duke committed to submit an LAR for Oconee Units 1, 2, and 3, and McGuire Units 1 and 2 (Option 1 of the GL) related to steam generator tube integrity and consistent with NRC-approved Revision 4 to TSTF-449 as described above. The LAR submitted herein fulfills this regulatory commitment.

In accordance with Duke administrative procedures and the Quality Assurance Program Topical Report, the plant-specific changes contained in this LAR have been reviewed and approved by the respective Oconee or McGuire Plant Operations Review Committee. This LAR has also been reviewed and approved by the Duke Nuclear Safety Review Board.

If you should have any questions regarding this submittal, please contact J. S. Warren at 704-875-5171.

Very truly yours,

G. R. Peterson

Attachments

Attachrnents:

1. Description and Assessment

2a. Proposed Facility Operating Licenses and Technical Specifications Changes (Mark-up) for Oconee Units 1, 2, and 3

2b. Proposed Technical Specifications Changes (Mark-up) for McGuire Units 1 and 2

3a. Proposed Facility Operating Licenses Pages, Technical Specifications Pages, and Bases Pages for Oconee Units 1, 2, and 3 (FUTURE)

3b. Proposed Technical Specifications Pages and Bases Pages for McGuire Units 1 and 2 (FUTURE)

4a. Proposed Technical Specifications Bases Changes (Mark-up) for Oconee Units 1, 2, and 3

4b. Proposed Technical Specifications Bases Changes (Mark-up) for McGuire Units 1 and 2

xc (with attachments):

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G. R. Peterson, affirms that he is the person who subscribed his name to the foregoing statement, and that all the matters and facts set forth herein are true and correct to the best of his knowledge.

G. R. Peterson, Site Vice President

Subscribed and sworn to me: August 11, 2006
Date

Freda K. Crump, Notary Public

My commission expires: August 17, 2006
Date

ATTACHMENT 1

Description and Assessment

1.0 INTRODUCTION

The proposed license amendment revises the requirements in the Technical Specification (TS) related to steam generator tube integrity. The changes are consistent with NRC approved Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler, TSTF-449, "Steam Generator Tube Integrity," Revision 4. The availability of this Technical Specification improvement was announced in the Federal Register on May 6, 2005 as part of the Consolidated Line Item Improvement Process (CLIIP).

2.0 DESCRIPTION OF PROPOSED AMENDMENT

Consistent with the NRC-approved Revision 4 of TSTF-449, the proposed TS changes include:

- Revised Oconee and McGuire TS 1.1 definition of LEAKAGE
- Revised Oconee and McGuire TS 3.4.13, "Reactor Coolant System (RCS) Operational LEAKAGE"
- New Oconee TS 3.4.16, "Steam Generator (SG) Tube Integrity"
- New McGuire TS 3.4.18, "Steam Generator (SG) Tube Integrity"
- Revised Oconee TS 5.5.10, "Steam Generator (SG) Tube Surveillance Program," (after steam generator replacement)
- Deleted Oconee TS 5.5.21, "Steam Generator (SG) Tube Surveillance Program," (until steam generator replacement)
- Revised McGuire TS 5.5.9, "Steam Generator (SG) Tube Surveillance Program"
- Revised Oconee and McGuire TS 5.6.8, "Steam Generator Tube Inspection Report"
- Revised Oconee and McGuire TS 5.2.1, "Onsite and Offsite Organizations"
- Revised Oconee Facility Operating Licenses Conditions 5 and 6

Proposed revisions to the TS Bases are also included in this application. As discussed in the NRC's model safety evaluation (SE), adoption of the revised TS Bases associated with TSTF-449, Revision 4 is an integral part of implementing this TS improvement. The changes to the affected TS Bases pages will be incorporated in accordance with the TS Bases Control Programs. The final two items listed above are additions to the CLIIP. These additional changes are discussed in Section 9.0.

3.0 BACKGROUND

The background for this application is adequately addressed by the NRC Notice of Availability published on May 6, 2005 (70 FR 24126), the NRC Notice for Comment published on March 2, 2005 (70 FR 10298), and TSTF-449, Revision 4.

4.0 REGULATORY REQUIREMENTS AND GUIDANCE

The applicable regulatory requirements and guidance associated with this application are adequately addressed by the NRC Notice of Availability published on May 6, 2005 (70 FR 24126), the NRC Notice for Comment published on March 2, 2005 (70 FR 10298), and TSTF-449, Revision 4.

5.0 TECHNICAL ANALYSIS

Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC (Duke) has reviewed the SE published on March 2, 2005 (70 FR 10298) as part of the CLIIP Notice for Comment. This included the NRC Staff's SE, the supporting information provided to support TSTF-449, and the changes associated with Revision 4 to TSTF-449. Duke has concluded that the justifications presented in the TSTF proposal and the SE prepared by the NRC Staff are applicable to Oconee Nuclear Station, Units 1, 2, and 3; and McGuire Nuclear Station, Units 1 and 2, and justify this amendment for the incorporation of the changes to the Oconee and McGuire TS.

6.0 REGULATORY ANALYSIS

A description of this proposed change and its relationship to applicable regulatory requirements and guidance was provided in the NRC Notice of Availability published on May 6, 2005 (70 FR 24126), the NRC Notice for Comment published on March 2, 2005 (70 FR 10298), and TSTF-449, Revision 4.

6.1 Verification and Commitments

The following information is provided to support the NRC Staff's review of this amendment application:

Plant Name, Unit Nos.	**Oconee Nuclear Station, Units 1, 2, and 3**
Steam Generator (SG) Model	BWC ROTSG
Effective Full Power Years (EFPY of service for currently installed SGs.	Unit 1: 1.2 yrs. Unit 2: 1.3 yrs. Unit 3: <1.3 yr.
Tubing Material	Alloy 690
Number of tubes per SG.	15,631
Number and percentage of tubes plugged in each SG.	SG — Tubes Plugged — % Plugged 1A — 31 — 0.20 1B — 19 — 0.12 2A — 6 — 0.04 2B — 4 — 0.03 3A — 0 — 0.0 3B — 0 — 0.0
Number of tubes repaired in each SG.	None
Degradation mechanism(s) identified.	Tube Support Plate Wear
Current primary-to-secondary leakage limits.	Per SG: 150 gpd Total: 300 gpd Leakage is evaluated at 77 °F.

Plant Name, Unit Nos.	Oconee Nuclear Station, Units 1, 2, and 3
Approved Alternate Tube Repair Criteria (ARC)	None
Approved SG Tube Repair Methods	None
Performance criteria for accident leakage.	Accident leakage is calculated at the TS limit.

Plant Name, Unit Nos.	McGuire Nuclear Station, Units 1 and 2
Steam Generator (SG) Model	CFR80
Effective Full Power Years (EFPY of service for currently installed SGs	Unit 1: 7.6 yrs. Unit 2: 6.7yrs.
Tubing Material	Alloy 690
Number of tubes per SG	6,633
Number and percentage of tubes plugged in each SG.	SG Tubes Plugged % Plugged 1A 2 0.03 1B 2 0.03 1C 5 0.08 1D 4 0.06 2A 20 0.30 2B 3 0.05 2C 1 0.02 2D 4 0.06
Number of tubes repaired in each SG.	None
Degradation mechanism(s) identified.	None
Current primary-to-secondary leakage limits.	Per SG: 135 gpd Total: 389 gpd Leakage is evaluated at 585 °F.
Approved Alternate Tube Repair Criteria (ARC)	None
Approved SG Tube Repair Methods	None
Performance criteria for accident leakage.	Accident leakage is calculated at the TS limits.

7.0 NO SIGNIFICANT HAZARDS CONSIDERATION

Duke has reviewed the proposed no significant hazards consideration determination published on March 2, 2005 (70 FR 10298) as part of the CLIIP. Duke has concluded that the proposed determination presented in the notice is applicable to Oconee and McGuire and the determination is hereby incorporated by reference to satisfy the requirements of 10 CFR 50.91(a).

8.0 ENVIRONMENTAL EVALUATION

Duke has reviewed the environmental evaluation included in the model SE published on March 2, 2005 (70 FR 10298) as part of the CLIIP. Duke has concluded that the Staff's findings presented in that evaluation are applicable to Oconee and McGuire and the evaluation is hereby incorporated by reference for this application.

9.0 PRECEDENT

This application is being made in accordance with the CLIIP. In TS 3.4.13, "RCS Operational Leakage," the CLIIP reduces the allowable primary to secondary leakage from any one SG to 150 gallons per day and eliminates the TS requirement for total primary to secondary leakage through all SGs. The current Oconee TS already limits primary to secondary leakage to 150 gallons per day for one SG, thus it is not necessary to implement this portion of the CLIIP at Oconee. The current McGuire TS limits the one SG value to 135 gallons per day and the limit through all SGs to 389 gallons per day. This portion of the CLIIP is not being implemented at McGuire because these lower leakage rate limits are assumed in the applicable safety analyses. Thus, McGuire will maintain the current more restrictive TS limits for primary to secondary leakage. Also for McGuire, Insert B3.4.13A, as shown in the traveler, is not used because it is not needed in order for this Bases to accurately describe the TS.

For Oconee only, this LAR deletes current Conditions 5 and 6 on Page 8a from FOLs DPR-38, DPR-47, and DPR-55 for Oconee Units 1, 2, and 3, respectively. These conditions were imposed upon the Oconee FOLs in Amendments 318, 318, and 318, also for Oconee Units 1, 2, and 3, respectively. These amendments were issued by NRC letter and SE dated December 15, 2000. As stated in the SER, the purpose of these license conditions was to ensure that Duke would perform an adequate evaluation to demonstrate that gross structural failure and leakage of the reroll repair joints, used at Oconee at that time, would not occur in the event of a LBLOCA. Further, this evaluation was to demonstrate that adequate safety margins and defense-in-depth would be maintained in the design and installation of the reroll repairs at Oconee Units 1, 2, and 3. These FOL conditions are now obsolete since all the Oconee steam generators have now been replaced and there are no repaired tubes in service, all defective tubes are now plugged. The SER stated that these FOL conditions applied only until the SGs were replaced. Also, the inspections, evaluations, and reporting requirements required by these conditions are superseded by the changes to TS 5.5.10 and 5.6.8 contained in the NRC CLIIP and within this LAR. Thus Duke has determined that this additional change is consistent with the implementation of the NRC CLIIP at Oconee Units 1, 2, and 3.

Additionally, for both Oconee and McGuire, this license amendment request contains a proposed change unrelated to the CLIIP. This proposed change revises an organizational

description in TS 5.2.1 to conform to a Duke application for consent to the indirect transfer of control of the facility operating licenses submitted by a Duke letter to the NRC dated August 5, 2005 and approved by NRC letter and SE dated February 7, 2006. This change is solely administrative in nature.

These are the variations or deviations from, or additions to, the TS changes described in TSTF-449, Revision 4, or the NRC Staff's model SE published on March 2, 2005 (70 FR 10298), that Duke is proposing. Since the variations, deviations, and additional changes contained in this LAR are either solely administrative in nature, remove obsolete requirements, or are conservative variations or deviations from the CLIIP, Duke has determined that these changes, as discussed here within Section 9, are bounded by the NRC's model SE, no significant hazards consideration, and environmental evaluation.

10.0 REFERENCES

Federal Register Notices:

Notice for Comment published on March 2, 2005 (70 FR 10298)

Notice of Availability published on May 6, 2005 (70 FR 24126)

Attachment 2a

Oconee Nuclear Station Units 1, 2, and 3

Proposed Facility Operating Licenses Changes and Technical Specifications Changes
(Mark-up)

OCONEE INSERTS

OCONEE INSERT 3.4.13 A

---------- NOTE ----------
Not required to be performed until 12 hours after establishment of steady state operation.

OCONEE INSERT B 3.4.13 A

The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is less than the conditions assumed in the safety analyses.

OCONEE INSERT B 3.4.13 B

d. Primary to Secondary LEAKAGE Through Any One SG

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 4). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

OCONEE INSERT B 3.4.13 C

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

OCONEE INSERTS

INSERT B 3.4.13 D (BWOG)

This SR verifies that primary to secondary LEAKAGE is less than or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with this LCO, as well as LCO 3.4.16, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Ref. 5. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

The Surveillance is modified by a Note which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The Surveillance Frequency of 72 hours is a reasonable interval to trend primary to secondary LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 5).

OCONEE INSERT B 3.4.13 E

4. NEI 97-06, "Steam Generator Program Guidelines."

5. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

OCONEE INSERTS

INSERT 5.5.10

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected and plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

   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 cool down and 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.

   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 150 gpd per SG, except for specific types of degradation at specific locations as described in paragraph c of the Steam Generator Program.

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

OCONEE INSERTS

INSERT 5.5.10 (cont.)

c. Provisions for SG tube repair 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 repair 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. An assessment of degradation 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 replacement.

   2. Inspect 100% of the tubes at sequential periods of 144, 108, 72, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

   3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). 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.

OCONEE INSERTS

INSERT 5.6.8

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with Specification 5.5.10, 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.

5. Steam Generator Circumferential Crack Report:

Following each inservice inspection of steam generator tubes, the NRC shall be notified of the following prior to returning the steam generators to service:

a. Indication of circumferential cracking in the secondary side roll (lower roll in the upper tubesheet or upper roll in the lower tubesheet) if rerolled.

b. Indication of circumferential cracking in the original roll or heat affected zone adjacent to the tube-to-tubesheet seal weld-if no reroll is present.

c. Determination of the best-estimate total leakage that would result from an analysis of the limiting Large Break Loss of Coolant Accident (LBLOCA) based on circumferential cracking in the original tube-to-tubesheet rolls, tube-to-tubesheet rerolls, and heat affected zones of seal welds as found during each inspection.

6. Demonstrate that the primary-to-secondary leakage following a LBLOCA, as described in Appendix A to BAW-2374, is acceptable, based on the as-found condition of the SGs. This is required to demonstrate that adequate margin and defense-in-depth are maintained. For the purpose of this evaluation, acceptable means a best estimate of the leakage expected in the event of a LBLOCA that would not result in a significant increase of radionuclide release (e.g., in excess of 10 CFR 100 limits). A summary of this evaluation shall be provided to the NRC within 3 months following completion of steam generator tube inservice inspection with the report required by Technical Specification 5.6.8, Item b.

FOR THE NUCLEAR REGULATORY COMMISSION

Roy Zimmerman, Acting Director
Office of Nuclear Reactor Regulation

Attachment:

1) Appendix A - Technical Specifications Renewed License No. DPR-38

Date of Issuance May 23, 2000

5. Steam Generator Circumferential Crack Report:

Following each inservice inspection of steam generator tubes, the NRC shall be notified of the following prior to returning the steam generators to service:

a. Indication of circumferential cracking in the secondary side roll (lower roll in the upper tubesheet or upper roll in the lower tubesheet) if rerolled.

b. Indication of circumferential cracking in the original roll or heat affected zone adjacent to the tube-to-tubesheet seal weld-if no reroll is present.

c. Determination of the best-estimate total leakage that would result from an analysis of the limiting Large Break Loss of Coolant Accident (LBLOCA) based on circumferential cracking in the original tube-to-tubesheet rolls, tube-to-tubesheet rerolls, and heat affected zones of seal welds as found during each inspection.

6. Demonstrate that the primary-to-secondary leakage following a LBLOCA, as described in Appendix A to BAW-2374, is acceptable, based on the as-found condition of the SGs. This is required to demonstrate that adequate margin and defense-in-depth are maintained. For the purpose of this evaluation, acceptable means a best estimate of the leakage expected in the event of a LBLOCA that would not result in a significant increase of radionuclide release (e.g., in excess of 10 CFR 100 limits). A summary of this evaluation shall be provided to the NRC within 3 months following completion of steam generator tube inset-vice inspection with the report required by Technical Specification 5.6.8, Item b.

FOR THE NUCLEAR REGULATORY COMMISSION

Roy P. Zimmerman, Acting Director
Office of Nuclear Reactor Regulation

Attachment:

1) Appendix A - Technical Specifications Renewed License No. DPR-47

Date of issuance: May 23, 2000

5. Steam Generator Circumferential Crack Report:

Following each inservice inspection of steam generator tubes, the NRC shall be notified of the following prior to returning the steam generators to service:

a. Indication of circumferential cracking in the secondary side roll (lower roll in the upper tubesheet or upper roll in the lower tubesheet) if rerolled.

b. Indication of circumferential cracking in the original roll or heat affected zone adjacent to the tube-to-tubesheet seal weld-if no reroll is present.

c. Determination of the best-estimate total leakage that would result from an analysis of the limiting Large Break Loss of Coolant Accident (LBLOCA) based on circumferential cracking in the original tube-to-tubesheet rolls, tube-to-tubesheet rerolls, and heat affected zones of seal welds as found during each inspection.

6. Demonstrate that the primary-to-secondary leakage following a LBLOCA, as described in Appendix A to BAW-2374, is acceptable, based on the as-found condition of the SGs. This is required to demonstrate that adequate margin and defense-in-depth are maintained. For the purpose of this evaluation, acceptable means a best estimate of the leakage expected in the event of a LBLOCA that would not result in a significant increase of radionuclide release (e.g., in excess of 10 CFR 100 limits). A summary of this evaluation shall be provided to the NRC within 3 months following completion of steam generator tube inservice inspection with the report required by Technical Specification 5.6.8, Item b.

FOR THE NUCLEAR REGULATORY COMMISSION

Roy P. Zimmerman, Acting Director
Office of Nuclear Reactor Regulation

Attachment:

1) Appendix A - Technical Specifications Renewed License No. DPR-55

Date of issuance: May 23, 2000

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1.1 Definitions (continued)

$\bar{E}$ – AVERAGE DISINTEGRATION ENERGY	$\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes, other than iodines, with half lives > 30 minutes, making up at least 95% of the total noniodine activity in the coolant.
LEAKAGE	LEAKAGE shall be:

a. Identified LEAKAGE

1. LEAKAGE, such as that from pump seals or valve packing (except RCP seal water injection or leakoff), that is captured and conducted to collection systems or a sump or collecting tank;

2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; or

3. Reactor Coolant System (RCS) LEAKAGE through a steam generator (SG) to the Secondary System; (primary to secondary LEAKAGE)

b. Unidentified LEAKAGE

All LEAKAGE (except RCP seal water injection or leakoff) that is not identified LEAKAGE.

c. Pressure Boundary LEAKAGE (primary to secondary)

LEAKAGE (except SG LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

MODE	A MODE shall correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE; and

~~d. 300 gallon per day total primary to secondary LEAKAGE through all steam generators (SGs); and~~

d. ~~e.~~ 150 gallon per day primary to secondary LEAKAGE through any one ~~SG~~. steam generator (SG)

APPLICABILITY: MODES 1, 2, 3, and 4.

Operational

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. OR Pressure boundary LEAKAGE exists. OR Primary to secondary LEAKAGE not within limit.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	12 hours 36 hours

2. Not applicable to primary to secondary LEAKAGE.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	----------NOTE---------- (5) (1.) Not required to be performed until 12 hours after establishment of steady state operation. ---------- Evaluate RCS Operational LEAKAGE.	72 hours
SR 3.4.13.2	~~Verify steam generator tube integrity is in accordance with the Steam Generator Tube Surveillance Program.~~	~~In accordance with the Steam Generator Tube Surveillance Program~~

Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG.

72 hours

INSERT 3.4.13 A

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 Steam Generator (SG) Tube Integrity

New TS 3.4.16

LCO 3.4.16 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube repair criteria shall be plugged in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection.	7 days
	AND	
	A.2 Plug the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3.	6 hours
	AND	
OR	B.2 Be in MODE 5.	36 hours
SG tube integrity not maintained.		

New TS 3.4.16

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.16.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following an SG tube inspection

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the UFSAR;

b. The Station Manager shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

c. The Vice-President, Oconee Nuclear Site, shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety;

d. The ~~Senior~~ Group Vice President, Nuclear Generation Department, will be the Senior Nuclear Executive and have corporate responsibility for overall nuclear safety; and

e. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

5.2.2 Station Staff

a. A non-licensed operator shall be onsite for each reactor containing fuel and an additional non-licensed operator shall be onsite for each control room from which a reactor is operating in MODES 1, 2, 3, or 4.

5.5 Programs and Manuals

5.5.9 Inservice Testing Program (continued)

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

5.5.10 Steam Generator (SG) Tube Surveillance Program

INSERT 5.5.10

----------NOTE----------
Applicable on each unit after steam generator replacement.

This program provides the controls for SG tube surveillance. The program shall include the following:

a. Examination Methods

Inservice inspection of steam generator tubing shall include non-destructive examination by eddy-current testing or other equivalent techniques. The inspection equipment shall provide a sensitivity that will detect defects with a penetration of 20 percent or more of the minimum allowable as-manufactured tube wall thickness.

5.5 Programs and Manuals

5.5.10 Steam Generator (SG) Tube Surveillance Program (continued)

b. Acceptance Criteria

The steam generator shall be considered operable after completion of the specified actions. All tubes examined exceeding the plugging limit shall be removed from service (e.g., plugged, stabilized).

c. Selection and Testing

The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 5.5.10-1. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in 5.5.10.d and the inspected tubes shall be verified acceptable per 5.5.10.e. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in both steam generators, with one or both steam generators being inspected. The tubes selected for these inspections shall be selected on a random basis except:

1. The first sample inspection during each inservice inspection of each steam generator shall include:

   a. All tubes that previously had detectable wall penetrations (>20%) and have not been plugged.

   b. At least 50% of the tubes inspected shall be in those areas where experience has indicated potential problems.

   c. A tube adjacent to any selected tube which does not permit passage of the eddy-current probe for tube inspection.

2. The tubes selected as the second and third samples (if required by Table 5.5.10-1) during each inservice inspection may be subjected to less than a full tube inspection provided:

   a. The tubes selected for these samples include the tubes from those areas of the tubesheet array where tubes with imperfections were previously found.

   b. The inspections include those portions of the tubes where imperfections were previously found.

INSERT 5.5.10

INSERT 5.5.10

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5.5.10 Steam Generator (SG) Tube Surveillance Program (continued)

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but no more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

NOTE: In all inspections, previously degraded tubes must exhibit significant (>10%) further wall penetrations to be included in the above percentage calculations.

d. Inspection Intervals

The above required inservice inspections of steam generator tubes shall be performed at the following frequencies.

1. Inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If the results of two consecutive inspections fall into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of 40 months.

2. If the results of the inservice inspection of a steam generator performed in accordance with Table 5.5.10-1 at 40 month intervals fall in Category C-3, subsequent inservice inspections shall be performed at intervals of not less than 10 months nor more than one fuel cycle after the previous inspection. The increase in inspection frequency shall apply until a subsequent inspection meets the conditions specified in 5.5.10.d.1 and the interval can be extended to a maximum of 40 months.

3. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 5.5.10-1 during the shutdown subsequent to any of the following conditions:

INSERT 5.5.10

5.5 Programs and Manuals

5.5.10 Steam Generator (SG) Tube Surveillance Program (continued)

a. A seismic occurrence greater than the Operating Basis Earthquake,

b. A loss-of-coolant accident requiring actuation of the engineered safeguards, or

c. A main steam line or feedwater line break.

4. After primary to secondary leakage in excess of the limits of Specification 3.4.13, an inspection of the affected steam generator will be performed in accordance with Table 5.5.10-1 with an initial inspection sample size of 6% of the tubes in the affected steam generator.

e. Definitions

As used in this specification:

1. Imperfection means an exception to the dimensions, finish or contour of a tube from that required by fabrication drawings or specifications. Eddy current testing indications below 20% of the nominal tube wall thickness, if detectable, may be considered as imperfections.

2. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either the inside or outside of a tube.

3. Degraded Tube means a tube containing imperfections ≥ 20% of the nominal wall thickness caused by degradation.

4. % Degradation means the percentage of the tube wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the plugging limit. A tube containing a defect is defective.

6. Plugging Limit means the imperfection depth beyond which the tube shall be either removed from service by plugging because it may become unserviceable prior to the next inspection; it is equal to 40% of the nominal tube or sleeve wall thickness.

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 5.5.10.d.

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nominal tube or sleeve wall thickness.

5.5.10 Steam Generator (SG) Tube Surveillance Program (continued)

8. Tube Inspection means an inspection of the steam generator tube from the point of entry completely to the point of exit.

INSERT 5.5.10

TABLE 5.5.10-1 (Page 1 of 2)
STEAM GENERATOR TUBE INSPECTION

1st Sample Inspection			2nd Sample Inspection		3rd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S tubes per S.G. (1)	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug defective tubes and inspect additional 2S tubes in this SG.	C-1	None	N/A	N/A
			C-2	Plug defective tubes and inspect additional 4S tubes in this SG.	C-1	None
					C-2	Plug defective tubes.
					C-3	Plug defective tubes and perform action for C-3 result of 1st Sample.
			C-3	Plug defective tubes and perform actions for C-3 results on 1st Sample.	N/A	N/A

(continued)

INSERT 5.5.10

TABLE 5.5.10-1 (Page 2 of 2)
STEAM GENERATOR TUBE INSPECTION

1st Sample Inspection			2nd Sample Inspection		3rd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
(continued)	C-3	Inspect 6S tubes in the S.G, plug defective tubes and inspect 2S tubes in the other S.G. Perform follow-on inspections in the other S.G. in accordance with results of the above inspection as applied to Table 5.5.10-1 Prompt Notification to NRC pursuant to 10 CFR 50.72	C-1	N/A	N/A	N/A
			C-2	N/A	N/A	N/A
			C-3 (2)	(a) If defects can be localized to an affected area, inspect all tubes in affected area and plug defective tubes. (b) If defects cannot be localized to an affected area, inspect all tubes in this S.G. and plug defective tubes.	C-1 C-2 C-3	N/A N/A N/A

Notes: (1) S=3(N/n)% Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

(2) Following an 18% random inspection (C-3 category inspection) an unaffected area is identified. The unaffected area will be logically and consistently defined based on generator design, defect location and characteristics. The criteria for accepting an area as unaffected depends on the number of defects found in the sample inspected in that area and are established such that there is a 0.05 or smaller probability of accepting the area as unaffected if it contains 30 or more defective tubes.

INSERT 5.5.10

5.5 Programs and Manuals

5.5.20 Battery Discharge Testing Program (continued)

b. If battery capacity is determined to be < 80% of the manufacturer's rating an OPERABILITY evaluation shall be initiated immediately and completed within the guidelines of the Oconee OPERABILITY program. If the OPERABILITY evaluation determines the battery OPERABLE, battery capacity shall be restored to ≥ 80% of the manufacturer's rating within a time frame commensurate with the safety significance of the issue. Otherwise, the battery shall be declared inoperable and the applicable Condition of Specification 3.8.3 shall be entered.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Battery Discharge Testing Program surveillance frequencies.

5.5.21 Steam Generator (SG) Tube Surveillance Program

----------NOTE----------
Applicable on each unit until steam generator replacement.

This program provides the controls for SG tube surveillance. The program shall include the following:

a. Examination Methods

Inservice inspection of steam generator tubing shall include non-destructive examination by eddy-current testing or other equivalent techniques. The inspection equipment shall provide a sensitivity that will detect defects with a penetration of 20 percent or more of the minimum allowable as-manufactured tube wall thickness.

b. Acceptance Criteria

The steam generator shall be considered operable after completion of the specified actions. All tubes examined exceeding the repair limit shall be repaired by sleeving or rerolling or removed from service (e.g., plugged, stabilized).

For Units 1 and 3, there are a number of steam generator tubes which exceed the tube repair limit as a result of tube end anomalies. These tubes are temporarily exempted from the requirements for sleeving, rerolling or removal from service, until repaired during or before the next Unit 1 and Unit 3 refueling outages (Unit 1 EOC 18, Unit 3 EOC 17 refueling outages, respectively). An analysis has been performed which confirms the operability

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5.5.21 Steam Generator (SG) Tube Surveillance Program (continued)

of Units 1 and 3 will not be impacted with these tubes in service until the next refueling outage on each of these units.

c. Selection and Testing

The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 5.5.21-1. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in 5.5.21.d and the inspected tubes shall be verified acceptable per 5.5.21.e. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in both steam generators, with one or both steam generators being inspected. The tubes selected for these inspections shall be selected on a random basis except:

1. The first sample inspection during each inservice inspection of each steam generator shall include:

   a. All tubes that previously had detectable wall penetrations (>20%) and have not been plugged or sleeve repaired in the affected area.

   b. At least 50% of the tubes inspected shall be in those areas where experience has indicated potential problems.

   c. A tube adjacent to any selected tube which does not permit passage of the eddy-current probe for tube inspection.

2. Tubes in the following Group(s) may be excluded from the first sample if all tubes in a Group in both OTSGs are inspected. No credit will be taken for these tubes in meeting minimum sample size requirements.

   Group A-1: Tubes within one, two, or three rows of the open inspection lane.

3. All tubes which have been repaired using the reroll process will have the new roll area inspected during the inservice inspection.

4. The tubes selected as the second and third samples (if required by Table 5.5.21-1) during each inservice inspection may be subjected to less than a full tube inspection provided:

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5.5.21 Steam Generator (SG) Tube Surveillance Program (continued)

a. The tubes selected for these samples include the tubes from those areas of the tubesheet array where tubes with imperfections were previously found.

b. The inspections include those portions of the tubes where imperfections were previously found.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but no more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

NOTES:

(1) In all inspections, previously degraded tubes must exhibit significant (>10%) further wall penetrations to be included in the above percentage calculations.

(2) Where special inspections are performed pursuant to 5.5.21.c.2, defective or degraded tubes found as a result of the inspection shall be included in determining the Inspection Results Category for that special inspection but need not be included in determining the Inspection Results Category for the general steam generator inspection, unless the mechanism of degradation is random in nature.

(3) Where special inspections are performed pursuant to 5.5.21.c.2, defective or degraded tube indications found in the new roll area as a result of the inspection and any indications found in the originally rolled region of the rerolled tube, need not be included in determining the Inspection Results Category for the general steam generator inspection.

5.5 Programs and Manuals

5.5.21 Steam Generator (SG) Tube Surveillance Program (continued)

d. Inspection Intervals

The above required inservice inspections of steam generator tubes shall be performed at the following frequencies.

1. Inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If the results of two consecutive inspections following service under all volatile treatment (AVT) conditions fall into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of 40 months.

2. If the results of the inservice inspection of a steam generator performed in accordance with Table 5.5.21-1 at 40 month intervals fall in Category C-3, subsequent inservice inspections shall be performed at intervals of not less than 10 months nor more than one fuel cycle after the previous inspection. The increase in inspection frequency shall apply until a subsequent inspection meets the conditions specified in 5.5.21.d.1 and the interval can be extended to a maximum of 40 months.

3. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 5.5.21-1 during the shutdown subsequent to any of the following conditions:

   a. A seismic occurrence greater than the Operating Basis Earthquake,

   b. A loss-of-coolant accident requiring actuation of the engineered safeguards, or

   c. A main steam line or feedwater line break.

4. After primary to secondary leakage in excess of the limits of Specification 3.4.13, an inspection of the affected steam generator will be performed in accordance with the following criteria:

   a. If the leaking tube is in a Group as defined in Section 5.5.21.c.2, all of the tubes in this Group in this steam generator will be inspected. If the results of this inspection fall into the C-3 category, additional inspections will be performed in the same Group in the other steam generator.

5.5 Programs and Manuals

5.5.21 Steam Generator (SG) Tube Surveillance Program (continued)

b. If the leaking tube has been repaired by the reroll process and is leaking in the new roll area, all tubes in the steam generator that have been repaired by the reroll process will have the new roll area inspected. If the results of this inspection fall into the C-3 category, additional inspections will be performed in the new roll area in the other steam generator.

c. If the leaking tube is not in a Group as defined in 5.5.21.d.4.a, then an inspection will be performed on the affected steam generator in accordance with Table 5.5.21-1 with an initial inspection sample size of 6% of the tubes in the affected steam generator.

e. Definitions

As used in this specification:

1. Imperfection means an exception to the dimensions, finish or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal tube or sleeve wall thickness, if detectable, may be considered as imperfections.

2. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either the inside or outside of a tube or a sleeve.

3. Degraded Tube means a tube or a sleeve containing imperfections ≥ 20% of the nominal wall thickness caused by degradation.

4. % Degradation means the percentage of the tube or sleeve wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the repair limit. A tube or sleeve containing a defect is defective.

6. Repair Limit means the imperfection depth beyond which the tube shall be either removed from service by plugging or repaired by sleeving or rerolling because it may become unserviceable prior to the next inspection; it is equal to 40% of the nominal tube or sleeve wall thickness. Axial tube imperfections of any depth observed between the primary side surface of the tube sheet clad and the end of the tube are excluded from this repair limit.

5.5 Programs and Manuals

5.5.21 Steam Generator (SG) Tube Surveillance Program (continued)

The Babcock and Wilcox process (or method) equivalent to the method described in report, BAW-1823P, Revision 1 will be used for sleeving repairs.

The new roll area must be free of degradation in order for the repair to be considered acceptable. The rerolling process used by Oconee is described in the Topical Report, BAW-2303P, Revision 4.

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 5.5.21.d.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry completely to the point of exit. The degraded tube above the new roll area can be excluded from future periodic inspection requirements because it is no longer part of the pressure boundary once the repair roll is installed.

TABLE 5.5.21-1 (Page 1 of 2)
STEAM GENERATOR TUBE INSPECTION

1st Sample Inspection			2nd Sample Inspection		3rd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S tubes per S.G. (1)	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug or repair defective tubes and inspect additional 2S tubes in this SG.	C-1	None	N/A	N/A
			C-2	Plug or repair defective tubes and inspect additional 4S tubes in this SG.	C-1	None
					C-2	Plug or repair defective tubes.
					C-3	Plug or repair defective tubes and perform action for C-3 result of 1st Sample.
			C-3	Plug or repair defective tubes and perform actions for C-3 results on 1st Sample.	N/A	N/A

(continued)

TABLE 5.5.21-1 (Page 1 of 2)
STEAM GENERATOR TUBE INSPECTION

1st Sample Inspection			2nd Sample Inspection		3rd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
(continued)	C-3	Inspect 6S tubes in the S.G, plug or repair Defective tubes and inspect 2S tubes in the other S.G. Perform follow-on inspections in the other S.G. in accordance with results of the above inspection as applied to Table 5.5.21-1 Prompt Notification to NRC pursuant to 10 CFR 50.72	C-1	N/A	N/A	N/A
			C-2	N/A	N/A	N/A
			C-3 (2)	(a) If defects can be localized to an affected area, inspect all tubes in affected area and plug or repair defective tubes. (b) If defects cannot be localized to an affected area, inspect all tubes in this S.G. and plug or repair defective tubes.	C-1 C-2 C-3	N/A N/A N/A

Notes: (1) S=3(N/n)% Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

(2) Following an 18% random inspection (C-3 category inspection) an unaffected area is identified. The unaffected area will be logically and consistently defined based on generator design, defect location and characteristics. The criteria for accepting an area as unaffected depends on the number of defects found in the sample inspected in that area and are established such that there is a 0.05 or smaller probability of accepting the area as unaffected if it contains 30 or more defective tubes.

5.6 Reporting Requirements (continued)

5.6.8 Steam Generator Tube Inspection Report

The steam generator tube inspection report shall comply with the following:

a. The number of tubes plugged or repaired in each steam generator shall be reported to the NRC within 30 days following the completion of the plugging or repair procedure.

b. The results of the steam generator tube inservice inspection shall be reported to the NRC within 3 months following completion of the inspection. This report shall include:

1. Number and extent of tubes inspected.

2. Location and percent of wall-thickness penetration for each indication of a degraded tube.

3. Identification of tubes plugged or repaired.

4. Number of tubes repaired by rerolling and number of indications detected in the new roll area of the repaired tubes.

c. Results of steam generator tube inspections which fall into Category C-3 and require notification to the NRC shall be reported prior to resumption of plant operation. The written report shall provide the results of investigations conducted to determine cause of the tube degradation and corrective measures taken to prevent recurrence.

d. The designation of affected and unaffected areas will be reported to the NRC when they are determined.

INSERT 5.6.8

Attachment 2b

McGuire Nuclear Station Units 1 and 2

Proposed Technical Specifications Changes (Mark-up)

MCGUIRE INSERTS

MCGUIRE INSERT 3.4.13 A

---------- NOTE ----------
Not required to be performed until 12 hours after establishment of steady state operation.

MCGUIRE INSERT B 3.4.13 B

Primary to Secondary LEAKAGE Through Any One SG

The limit of 135 gallons per day per SG is based on the LEAKAGE rate assumptions in the accident analyses (Ref. 9). This limit is more conservative than the performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 7) which is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The 135 gallons per day limit in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

MCGUIRE INSERT B 3.4.13 C

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 135 gallons per day cannot be measured accurately by an RCS water inventory balance.

MCGUIRE INSERTS

MCGUIRE INSERT B 3.4.13 D (WOG)

This SR verifies that primary to secondary LEAKAGE is less than or equal to 135 gallons per day through any one SG or 389 gallons per day total for all SGs. Satisfying the primary to secondary LEAKAGE limit ensures that the assumptions of the safety analyses are met (Ref. 3). If this SR is not met, compliance with this LCO, as well as LCO 3.4.18, "Steam Generator Tube Integrity," should be evaluated. The 135 and 389 gallons per day limits are measured at a temperature of 585 °F as described in Ref. 3. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

The Surveillance is modified by a Note which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The Surveillance Frequency of 72 hours is a reasonable interval to trend primary to secondary LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 8).

MCGUIRE INSERT B 3.4.13 E

7. NEI 97-06, "Steam Generator Program Guidelines."

8. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

9. UFSAR, Table 15-24.

MCGUIRE INSERTS

MCGUIRE INSERT 5.5.9

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

   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 cool down and 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.

   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 0.27 gpm total, except for specific types of degradation at specific locations as described in paragraph c of the Steam Generator Program.

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

c. Provisions for SG tube repair 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.

MCGUIRE INSERTS

MCGUIRE INSERT 5.5.9 (cont.)

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 repair 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. An assessment of degradation 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 replacement.

2. Inspect 100% of the tubes at sequential periods of 144, 108, 72, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). 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.

MCGUIRE INSERTS

INSERT 5.6.8

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with Specification 5.5.9, 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 tube plugging in each SG.

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1.1 Definitions (continued)

ENGINEERED SAFETY FEATURE (ESF) RESPONSE TIME	The ESF RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays, where applicable. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and the methodology for verification have been previously reviewed and approved by the NRC.
LEAKAGE	LEAKAGE shall be:

a. Identified LEAKAGE

1. LEAKAGE, such as that from pump seals or valve packing (except reactor coolant pump (RCP) seal water injection or leakoff), that is captured and conducted to collection systems or a sump or collecting tank;

2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; or

(primary to secondary LEAKAGE)

3. Reactor Coolant System (RCS) LEAKAGE through a steam generator (SG) to the Secondary System;

b. Unidentified LEAKAGE

All LEAKAGE (except RCP seal water injection or leakoff) that is not identified LEAKAGE;

c. Pressure Boundary LEAKAGE

primary to secondary

LEAKAGE (except SG LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

(continued)

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE;

d. 389 gallons per day total primary to secondary LEAKAGE through all steam generators (SGs); and

e. 135 gallons per day primary to secondary LEAKAGE through any one SG.

steam generator (SG)

APPLICABILITY: MODES 1, 2, 3, and 4.

Operational

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE.	A.1 Reduce LEAKAGE to within limits. or primary to secondary LEAKAGE	4 hours
B. Required Action and associated Completion Time of Condition A not met. OR Pressure boundary LEAKAGE exists.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

OR
Primary to secondary LEAKAGE not within limit.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.13.1 ----------NOTE---------- 1. Not required to be performed ~~in MODE 3 or 4~~ until 12 hours after establishment of steady state operation. 2. Not applicable to primary to secondary LEAKAGE	---------NOTE--------- Only required to be performed during steady state operation
Verify RCS Operational LEAKAGE is within limits by performance of RCS water inventory balance.	72 hours
SR 3.4.13.2 ~~Verify steam generator tube integrity is in accordance with the Steam Generator Tube Surveillance Program.~~ Verify primary to secondary LEAKAGE is ≤ 135 gallons per day through any one SG or 389 gallons per day through all SGs.	~~In accordance with the Steam Generator Tube Surveillance Program~~ 72 hours

INSERT 3.4.13A

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.18 Steam Generator (SG) Tube Integrity

New TS 3.4.18

LCO 3.4.18 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube repair criteria shall be plugged in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program.	A.1	Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection.	7 days
	AND		
	A.2	Plug the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	6 hours
	AND		
OR	B.2	Be in MODE 5.	36 hours
SG tube integrity not maintained.			

New TS 3.4.18

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.18.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.18.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the UFSAR;

b. The Station Manager shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

c. The Vice President of McGuire Nuclear Site shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety;

d. The ~~Executive~~ Group Vice President Nuclear Generation Department will be the Senior Nuclear Executive and have corporate responsibility for overall nuclear safety; and

e. The individuals who train the operating staff, carry out radiation protection, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

(continued)

5.5 Programs and Manuals (continued)

5.5.8 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components including applicable supports. The program shall include the following:

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as follows:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

5.5.9 Steam Generator (SG) Tube Surveillance Program

~~This program provides controls for the inservice inspection of steam generator tubes to ensure that the structural integrity of this portion of the RCS is maintained. The program for inservice inspection of steam generator tubes is based on a modification of Regulatory Guide 1.83, Revision 1. The program shall include:~~

INSERT 5.5.9

(continued)

5.5 Programs and Manuals (continued)

INSERT 5.5.9

5.5.9.1 Steam Generator Sample Selection and Inspection

Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum of steam generators specified in Table 5.5-1.

5.5.9.2 Steam Generator Tube Sample Selection and Inspection

The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 5.5-2. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 5.5.9.3 and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 5.5.9.4. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators; the tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas;

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

1. All nonplugged tubes that previously had detectable wall penetrations (greater than 20%),

2. Tubes in those areas where experience has indicated potential problems, and

3. A tube inspection (pursuant to Specification 5.5.9.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

c. The tubes selected as the second and third samples (if required by Table 5.5-2) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found, and

(continued)

INSERT 5.5.9

5.5.9.2 Steam Generator Tube Sample Selection and Inspection (continued)

2. The inspections include those portions of the tubes where imperfections were previously found.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes must exhibit significant (greater than 10%) further wall penetrations to be included in the above percentage calculations.

5.5.9.3 Inspection Frequencies

The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection after the steam generator replacement shall be performed after at least 6 Effective Full Power Months but within 24 calendar months of initial criticality after steam generator replacement. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months;

(continued)

5.5 Programs and Manuals

5.5.9.3 Inspection Frequencies (continued)

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 5.5-2 at 40-month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 5.5.9.3.a; the interval may then be extended to a maximum of once per 40 months; and

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 5.5-2 during the shutdown subsequent to any of the following conditions:

1. Reactor-to-secondary tubes leaks (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.4.13,

2. A seismic occurrence greater than the Operating Basis Earthquake,

3. A loss-of-coolant accident requiring actuation of the Engineered Safety Features, or

4. A main steam line or feedwater line break.

The provisions of SR 3.0.2 are applicable to the SG Tube Surveillance Program test frequencies.

5.5.9.4 Acceptance Criteria

a. As used in this specification:

1. Imperfection means an exception to the dimensions, finish or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal tube wall thickness, if detectable, may be considered as imperfections;

2. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either inside or outside of a tube;

INSERT 5.5.9

(continued)

5.5 Programs and Manuals

5.5.9.4 Acceptance Criteria (continued)

3. Degraded Tube means a tube containing imperfections greater than or equal to 20% of the nominal tube wall thickness caused by degradation;

4. % degradation means the percentage of the tube wall thickness affected or removed by degradation;

5. Defect means an imperfection of such severity that it exceeds the plugging limit. A tube containing a defect is defective;

6. Plugging Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging. The plugging limit is equal to 40% of the nominal tube wall thickness.

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 5.5.9.3.c. above;

8. Tube Inspection means an inspection of the steam generator tube from the point of entry completely around the U-bend to the point of exit; and

9. Preservice Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed prior to initial POWER OPERATION using the equipment and techniques expected to be used during subsequent inservice inspections.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions required by Table 5.5-2.

INSERT 5.5.9

(continued)

TABLE 5.5-1 (Page 1 of 1)

MINIMUM NUMBER OF STEAM GENERATORS TO BE INSPECTED DURING INSERVICE INSPECTION

Preservice Inspection	No	Yes
No. of Steam Generators per Unit	Four	Four
First Inservice Inspection after the Steam Generator Replacement	All	Two
Second & Subsequent Inservice Inspections	One[1]	One[2]

Table Notation

1. The inservice inspection may be limited to one steam generator on a rotating schedule encompassing 3 N % of the tubes (where N is the number of steam generators in the unit) if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. Note that under some circumstances, the operating conditions in one or more steam generators may be found to be more severe than those in other steam generators. Under such circumstances the sample sequence shall be modified to inspect the most severe conditions.

2. Each of the other two steam generators not inspected during the first inservice inspections after the steam generator replacement shall be inspected during the second and third inspections. The fourth and subsequent inspections shall follow the instructions described in 1 above.

INSERT 5.5.9

TABLE 5.5-2
STEAM GENERATOR TUBE INSPECTION

1ST SAMPLE INSPECTION			2ND SAMPLE INSPECTION		3RD SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S tubes per SG	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug defective tubes and inspect additional 2S tubes in this SG	C-1	None	N/A	N/A
			C-2	Plug defective tubes and inspect additional 4S tubes in this SG	C-1	None
					C-2	Plug defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N/A	N/A
	C-3	Inspect all tubes in this SG, plug defective tubes and inspect 2S tubes in each other SG	All other SGs are C-1	None	N/A	N/A
			Some SGs C-2 but no additional SGs are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional SG is C-3	Inspect all tubes in each SG and plug defective tubes.	N/A	N/A

S = 3N/n % Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

INSERT 5.5.9

5.6.8 Steam Generator Tube Inspection Report

a. The number of tubes plugged in each steam generator shall be reported to the NRC within 15 days following completion of the program;

b. The complete results of the Steam Generator Tube Surveillance Program shall be reported to the NRC within 12 months following the completion of the program and shall include:

1. Number and extent of tubes inspected,

2. Location and percent of wall-thickness penetration for each indication of an imperfection, and

3. Identification of tubes plugged.

INSERT 5.6.8

(continued)

Attachment 3a (FUTURE)

Oconee Nuclear Station Units 1, 2, and 3

Proposed Facility Operating Licenses Pages, Technical Specifications Pages, and Bases Pages

Attachment 3b (FUTURE)

McGuire Nuclear Station Units 1 and 2

Proposed Technical Specifications Pages and Bases Pages

Attachment 4a

Oconee Nuclear Station Units 1, 2, and 3

Proposed Technical Specifications Bases Changes (Mark-up)

BASES (continued)

LCO

The purpose of this LCO is to require two loops to be available for heat removal thus providing redundancy. The LCO requires the two loops to be OPERABLE with the intent of requiring both SGs to be capable of transferring heat from the reactor coolant at a controlled rate. Forced reactor coolant flow is the required way to transport heat, although natural circulation flow provides adequate removal. A minimum of one running RCP meets the LCO requirement for one loop in operation.

The Note permits a limited period of operation without RCPs. All RCPs may not be in operation for ≤ 8 hours per 24 hour period for the transition to or from the Decay Heat Removal (DHR) System, and otherwise may be de-energized for ≤1 hour per 8 hour period. This means that natural circulation has been established. When in natural circulation, boron reduction is prohibited because an even concentration distribution throughout the RCS cannot be ensured. Core outlet temperature is to be maintained at least 10°F below the saturation temperature so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

In MODES 3, 4, and 5, it is sometimes necessary to stop all RCP or LPI pump forced circulation (e.g., change operation from one DHR loop to the other, to perform surveillance or startup testing, to perform the transition to and from DHR mode cooling, or to avoid operation below the RCP minimum net positive suction head limit). This is acceptable because natural circulation is adequate for heat removal, or the reactor coolant temperature can be maintained subcooled and boron stratification affecting reactivity control is not expected.

OPERABLE

An OPERABLE RCS loop consists of at least one OPERABLE RCP and an SG that is ~~capable of transferring decay heat to the secondary fluid~~. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, the heat load is lower than at power; therefore, one RCS loop in operation is adequate for transport and heat removal. A second RCS loop is required to be OPERABLE but not in operation for redundant heat removal capability.

BASES

LCO (continued)

so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 1 also permits the DHR pumps to be stopped for ≤ 1 hour per 8 hour period. When the DHR pumps are stopped, no alternate heat removal path exists, unless the RCS and SGs have been placed in service in forced or natural circulation. The response of the RCS without the DHR loop depends on the core decay heat load and the length of time that the DHR pumps are stopped. As decay heat diminishes, the effects on RCS temperature and pressure diminish. Without cooling by DHR, higher heat loads will cause the reactor coolant temperature and pressure to increase at a rate proportional to the decay heat load. Because pressure can increase, the applicable system pressure limits (pressure and temperature (P/T) or low temperature overpressure protection (LTOP) limits) must be observed and forced DHR flow or heat removal via the SGs must be re-established prior to reaching the pressure limit. The circumstances for stopping both DHR trains are to be limited to situations where:

a. Pressure and temperature increases can be maintained well within the allowable pressure (P/T and LTOP) and 10°F subcooling limits; or

b. An alternate heat removal path through the SG is in operation.

Note 2 allows a DHR loop to be considered OPERABLE if it is capable of being manually (locally or remotely) realigned to the DHR mode of operation and is not otherwise inoperable. This provision is necessary because of the dual function of the components that comprise the decay heat removal mode of the Low Pressure Injection System.

An OPERABLE RCS loop consists of at least one OPERABLE RCP and an SG that is ~~capable of transferring decay heat to the secondary fluid~~.

OPERABLE

Similarly for the DHR loops, an OPERABLE DHR loop is comprised of the OPERABLE LPI pump(s) capable of providing forced flow to the LPI heat exchanger(s). LPI pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing.

BASES

LCO (continued)

Note 2 allows one required DHR loop to be inoperable for a period of ≤ 2 hours provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

Note 3 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting DHR loops to not be in operation when at least one RCP is in operation. This Note provides for the transition to MODE 4 where an RCP is permitted to be in operation and replaces the RCS circulation function provided by the DHR loops.

Note 4 allows a DHR loop to be considered OPERABLE during alignment and when aligned for low pressure injection if it is capable of being manually (locally or remotely) realigned to the DHR mode of operation and is not otherwise inoperable. This provision is necessary because of the dual requirements of the components that comprise the low pressure injection/decay heat removal system.

To be considered OPERABLE, a DHR loop must consist of a pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the temperature. The flow path starts in one of the RCS hot legs and is returned to reactor vessel via one or both Core Flood tank injection nozzles. The BWST recirculation crossover line through valves LP-40 and LP-41 may be part of a flow path if it provides adequate decay heat removal capability. The operability of the operating DHR loop and the supporting heat sink is dependent on the ability to maintain the desired RCS temperature. LPSW and ECCW are required to support the OPERABLE DHR train(s). One LPSW pump and one ECCW header can simultaneously support one or two DHR trains. Single failure protection is not required for LPSW or support systems in these modes.

To be considered OPERABLE, DHR loops must be capable of being powered and are able to provide flow if required. An OPERABLE SG can perform as a heat sink when it has an adequate water level and is OPERABLE in accordance with the Steam Generator Tube Surveillance Program.

APPLICABILITY

In MODE 5 with loops filled, forced circulation is provided by this LCO to remove decay heat from the core and to provide proper boron mixing. One loop of DHR in operation provides sufficient circulation for these purposes.

Operation in other MODES is covered by:
LCO 3.4.4, "RCS Loops – MODES 1 and 2";
LCO 3.4.5, "RCS Loops – MODE 3";

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

During unit life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area ~~are~~ is necessary. Separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur detrimental to the safety of the facility and the public.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analysis radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA). However, the ability to monitor leakage provides advance warning to permit unit shutdown before a LOCA occurs. This advantage has been shown by "leak before break" studies.

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The steam line break (SLB) ~~and Loss of Load Safety~~ analyses assume total primary to secondary LEAKAGE greater than ~~300~~ 150 gallon per day per SG as the initial condition.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a SLB accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid and can be released to the environment.

INSERT B 3.4.13A

The safety analysis assumptions for the SLB accident bounds 300 gallon per day primary to secondary LEAKAGE in one generator as an initial condition. The dose consequences resulting from the SLB accident are within the limits defined in 10 CFR 100.

RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36 (Ref.3).

LCO

RCS LEAKAGE includes leakage from connected systems up to and including the second normally closed valve for systems which do not penetrate containment and the outermost isolation valve for systems which penetrate containment. Loss of reactor coolant through reactor coolant pump seals and system valves to connecting systems which vent to the gas vent header and from which coolant can be returned to the RCS shall not be considered as RCS LEAKAGE.

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals, gaskets, and steam generator tubes is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

BASES

LCO (continued)

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS makeup system. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through All Steam Generators (SGs)

Total primary to secondary LEAKAGE amounting to 300 gallon per day through all SGs produces acceptable offsite doses in the SLB accident analysis. Violation of this LCO could exceed the offsite dose limits for this accident. Primary to secondary LEAKAGE must be included in the total allowable limit for identified LEAKAGE.

INSERT B 3.4.13 B

e. Primary to Secondary LEAKAGE through Any One SG

The 150 gallon per day limit on one SG is equivalent to a total of 300 gallon per day primary to secondary LEAKAGE allocated equally between the two generators.

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leaktight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

BASES (continued)

ACTIONS

A.1

or

If unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE are in excess of the LCO limits, the LEAKAGE must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

, or primary to secondary LEAKAGE is not within limit,

or

If any pressure boundary LEAKAGE exists or if unidentified, identified, or primary to secondary LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. The reactor must be brought to MODE 3 within 12 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

The Completion Times allowed are reasonable, based on operating experience, to reach the required conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 5, the pressure stresses acting on the RCPB are much lower and further deterioration is much less likely.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Evaluation of RCS LEAKAGE ensures identified and unidentified leakage is maintained within the associated LCO limits and ensures that the integrity of the RCPB is maintained. Identified and unidentified LEAKAGE is determined by performance of an RCS water inventory balance. Primary to secondary LEAKAGE is measured by effluent monitoring within the secondary systems or comparison of primary and secondary radioisotope concentrations. These methods provide the required leakage detection sensitivity to ensure leakage is within limits.

is

The surveillance is modified by two Notes.

The RCS water inventory balance must be performed with the reactor at steady state operating conditions and near operating pressure. Therefore, Note 1 states that this SR is not required to be performed until 12 hours after establishment of steady state operation. This 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 (continued)

Steady state operation is required to perform a proper water inventory balance since calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP pump seal injection and return flows.

An early warning of LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level.

INSERT B 3.4.13C

These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

SR 3.4.13.2

INSERT B 3.4.13 D (BWOG)

~~This SR provides the means necessary to determine SG OPERABILITY in an operational MODE. The requirement to demonstrate SG tube integrity in accordance with the Steam Generator Tube Surveillance Program emphasizes the importance of SG tube integrity, even though this Surveillance cannot be performed at normal operating conditions.~~

REFERENCES

1. UFSAR, Section 3.1.
2. UFSAR, Chapter 15.
3. 10 CFR 50.36.

INSERT B 3.4.13 E

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator 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. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops - MODES 1 and 2," LCO 3.4.5, "RCS Loops - MODE 3," LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled."

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and 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.

Specification 5.5.10, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.10, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.10. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to the operational LEAKAGE rate limits in LCO 3.4.13, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes cooldown via the main steam atmospheric dump valves.

The analysis for design basis accidents and transients other than a 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 bounds the primary to secondary LEAKAGE of 150 gallons per day per SG. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, "RCS Specific Activity," limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 2), 10 CFR 100 (Ref. 3) or the NRC approved licensing basis (e.g., a small fraction of these limits).

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.10, "Steam Generator Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

BASES

LCO (continued)

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term "significant" is defined as "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established." For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 150 gpd per SG, except for specific types of degradation at specific locations where the NRC has approved greater accident induced leakage. The accident induced leakage rate includes any primary to secondary LEAKAGE existing prior to the accident in addition to primary to secondary LEAKAGE induced during the accident.

BASES

LCO (continued)

The operational LEAKAGE performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational LEAKAGE is contained in LCO 3.4.13, "RCS Operational LEAKAGE," and limits primary to secondary LEAKAGE through any one SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

A.1 and A.2

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube repair criteria but were not plugged in accordance with the Steam Generator Program as required by SR 3.4.16.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG repair criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection, which ever is shorter. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

BASES

Actions (continued)

A Completion Time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may not have tube integrity.

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the "as found" condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube repair criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, non-destructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.16.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.5.10 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

SR 3.4.16.2

During a SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. The tube repair criteria delineated in Specification 5.5.10 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube repair criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

The Frequency of prior to entering MODE 4 following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the repair criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."
2. 10 CFR 50 Appendix A, GDC 19.
3. 10 CFR 100.
4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.
5. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.
6. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines."

Attachment 4b

McGuire Nuclear Station Units 1 and 2

Proposed Technical Specifications Bases Changes (Mark-up)

BASES

APPLICABLE SAFETY ANALYSES (continued)

assuming the number of RCS loops in operation is consistent with the Technical Specifications. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The primary coolant flowrate, and thus the number of RCPs in operation is an important assumption in all accident analyses (Ref. 1).

Steady state DNB analysis has been performed for the four RCS loop operation. For four RCS loop operation, the steady state DNB analysis, which generates the pressure and temperature Safety Limit (SL) (i.e., the departure from nucleate boiling ratio (DNBR) limit) assumes a maximum power level of 118% RTP. This is the design overpower condition for four RCS loop operation. The DNBR limit defines a locus of pressure and temperature points that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

The plant is designed to operate with all RCS loops in operation to maintain DNBR above the SL, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops—MODES 1 and 2 satisfy Criterion 2 of 10 CFR 50.36 (Ref. 2).

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, four pumps are required in MODES 1 and 2.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program.

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

BASES

LCO (continued)

characteristics of the RCS are changed. The 1 hour time period specified is adequate to perform the desired tests, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentration less than required to assure the SDM of LCO 3.1.1 and maintain Keff < 0.99, thereby maintaining an adequate margin to criticality. Boron reduction with coolant at boron concentration less than required to assure SDM and Keff < 0.99 is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program, which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, three RCS loops OPERABLE and three RCS loops in operation, applies to MODE 3 with RTBs in the closed position. The least stringent condition, that is, three RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the RTBs open.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops—MODES 1 and 2";
LCO 3.4.6, "RCS Loops—MODE 4";
LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled";
LCO 3.4.17, "RCS Loops—Test Exceptions";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

LCO (continued)

Note 1 permits all RCPs or RHR pumps to be de-energized for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits the de-energizing of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant with boron concentrations less than required to meet SDM of LCO 3.1.1 and maintain Keff < 0.99, therefore maintaining an adequate margin to criticality. Boron reduction with coolant of boron concentrations less than required to assure SDM and maintain Keff < 0.99 is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures or that pressurizer water volume be < 92% (1600 ft^3) before the start of an RCP with any RCS cold leg temperature ≤ 300°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program, which has the minimum water level specified in SR 3.4.6.2. The water level is maintained by an OPERABLE AFW train in accordance with LCO 3.7.5, "Auxiliary Feedwater System."

Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are

BASES

LCO (continued)

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

Note 3 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures or that pressurizer water volume be < 92% (1600 ft^3) before the start of a reactor coolant pump (RCP) with an RCS cold leg temperature ≤ 300°F. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An OPERABLE SG can perform as a heat sink when it has an adequate water level and is OPERABLE in accordance with the Steam Generator Tube Surveillance Program.

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side narrow range water level of at least two SGs is required to be ≥ 12%.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops—MODES 1 and 2";
LCO 3.4.5, "RCS Loops—MODE 3";
LCO 3.4.6, "RCS Loops—MODE 4";
LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled";
LCO 3.4.17 "RCS Loops—Test Exceptions";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

BASES

LCO (continued)

LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. Pressure boundary LEAKAGE is nonisolable LEAKAGE from the RCPB through an RCS component body, pipe wall or vessel wall. LEAKAGE past seals and gaskets and SG LEAKAGE are not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified or total LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE captured by the pressurizer relief tank and reactor coolant drain tank, as well as quantified LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through All Steam Generators (SGs)

Total primary to secondary LEAKAGE amounting to 389 gpd through all SGs produces acceptable offsite doses in the accident analysis. Violation of this LCO could exceed the offsite dose limits for the previously described accidents. Primary to secondary LEAKAGE must be included in the total allowable limit for identified LEAKAGE.

INSERT B 3.4.13 B

e. ~~Primary to Secondary LEAKAGE through Any One SG~~

~~The 135 gallons per day limit on one SG is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line rupture. If leaked through many cracks, the cracks are very small, and the above assumption is conservative.~~

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable unidentified LEAKAGE.

ACTIONS

A.1

or

Unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

or primary to secondary LEAKAGE is not within limits,

or

If any pressure boundary LEAKAGE exists, or if unidentified LEAKAGE, or identified LEAKAGE, or primary to secondary LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first

BASES

SURVEILLANCE REQUIREMENTS (continued)

appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance. Primary to secondary LEAKAGE is also measured by performance of an RCS water inventory balance in conjunction with effluent monitoring within the secondary steam and feedwater systems.

The surveillance is modified by two Notes. Note 1 states that

The RCS water inventory balance must be performed with the reactor at steady state operating conditions and near operating pressure. performed Therefore, this SR is not required to be completed in MODES 3 and 4 until 12 hours of steady state operation near operating pressure have been established. after establishment

Steady state operation is required to perform a proper inventory balance; calculations during maneuvering are not useful and a Note requires the Surveillance to be met when steady state is established. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

INSERT B 3.4.13C

The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. A Note under the Frequency column states that this SR is required to be performed during steady state operation.

SR 3.4.13.2

INSERT B 3.4.13 D WOG

This SR provides the means necessary to determine SG OPERABILITY in an operational MODE. The requirement to demonstrate SG tube integrity in accordance with the Steam Generator Tube Surveillance Program emphasizes the importance of SG tube integrity, even though this Surveillance cannot be performed at normal operating conditions.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.

2. Regulatory Guide 1.45, May 1973.

3. UFSAR, Section 15.

4. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).

5. UFSAR, Table 18-1.

6. McGuire License Renewal Commitments MCS-1274.00-00-0016, Section 4.29, RCS Operational Leakage Monitoring Program.

INSERT
B 3.4.13 E

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.18 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator 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. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops - MODES 1 and 2," LCO 3.4.5, "RCS Loops - MODE 3," LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled."

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and 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.

Specification 5.5.9, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.9, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.9. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to the operational LEAKAGE rate limits in LCO 3.4.13, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes main steam isolation valve closure and cooldown via the SG safety valves or blowdown through the SG PORVs.

The analysis for design basis accidents and transients other than a 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 SGs of 389 gallons per day. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, "RCS Specific Activity," limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 2), 10 CFR 100 (Ref. 3) or the NRC approved licensing basis (e.g., a small fraction of these limits).

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall and any repairs made to it, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.9, "Steam Generator Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

BASES

LCO (continued)

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term "significant" is defined as "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established." For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 0.27 gpm total, except for specific types of degradation at specific locations where the NRC has approved greater accident induced leakage. The accident induced leakage rate includes any primary to secondary LEAKAGE existing prior to the accident in addition to primary to secondary LEAKAGE induced during the accident.

BASES

LCO (continued)

The operational LEAKAGE performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational LEAKAGE is contained in LCO 3.4.13, "RCS Operational LEAKAGE," and limits primary to secondary LEAKAGE through any one SG to 135 gallons per day or 389 gallons per day total. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

A.1 and A.2

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube repair criteria but were not plugged in accordance with the Steam Generator Program as required by SR 3.4.18.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG repair criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection, which ever is shorter. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

BASES

Actions (continued)

A Completion Time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may not have tube integrity.

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.18.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the "as found" condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube repair criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, non-destructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.18.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.5.9 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

SR 3.4.18.2

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. The tube repair criteria delineated in Specification 5.5.9 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube repair criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

The Frequency of prior to entering MODE 4 following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the repair criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."
2. 10 CFR 50 Appendix A, GDC 19.
3. 10 CFR 100.
4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.
5. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.
6. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines."