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June 9, 2003

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

Subject: Duke Energy Corporation
Catawba Nuclear Station, Units 1 and 2
Docket Numbers 50-413 and 50-414
Proposed Technical Specifications (TS) Amendments
Revision to Steam Generator TS
TAC Nos. MB7842 and MB7843

References:

1. Letter from Duke Energy Corporation to NRC, same subject, dated February 25, 2003

2. Letter from NRC to Duke Energy Corporation, Request for Additional Information, dated April 30, 2003

3. Letter from NRC to Duke Energy Corporation, Position on Technical Specifications for Steam Generator Inspection, dated May 29, 2003

Reference 1 requested amendments to the Operating Licenses and TS to incorporate changes to a number of TS and Bases sections for Catawba Units 1 and 2 in response to the industry initiative known as the NEI Generic License Change Package (GLCP). The NRC provided Requests for Additional Information via References 2 and 3. The purpose of this letter is to formally respond to the Requests for Additional Information and to submit revised proposed TS and Bases pages as necessary.

Attachment 1 to this letter contains Duke Energy Corporation's response to the Requests for Additional Information. The format of the response is to restate the NRC question/comment, followed by the associated response.

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Attachment 2 to this letter contains the revised proposed TS and Bases pages in conjunction with the responses. In order to facilitate NRC review, all of the TS and Bases pages originally transmitted via Reference 1 are being resubmitted in their entirety. Duke Energy Corporation has concluded that the original No Significant Hazards Consideration Analysis and Environmental Analysis transmitted via Reference 1 continue to remain valid as a result of this response.

Part of this response to the Requests for Additional Information involves the steam generator Structural Integrity Performance Criterion in revised TS 5.5.9. Duke Energy Corporation has determined that the proposed revised criterion is appropriate for Catawba. However, the final version of this criterion will impact other plants in the industry as well. For this reason, the Steam Generator Management Program (SGMP) Issues Integration Group (IIG) has elected to conduct an evaluation of this criterion in order to verify its appropriateness on a generic basis. The IIG determined that it is acceptable for Duke Energy Corporation to submit the enclosed version of this criterion for Catawba as part of this response. However, it should be noted that the possibility exists that the criterion may need to be changed for other plants pending the completion of the evaluation. The evaluation is tentatively scheduled for completion by June 30, 2003.

Pursuant to 10 CFR 50.91, a copy of this letter is being sent to the appropriate State of South Carolina official.

Inquiries on this matter should be directed to L.J. Rudy at (803) 831-3084.

Very truly yours,

Gary R. Peterson

LJR/s

Attachments

Gary 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.

Gary R. Peterson, Vice President

Subscribed and sworn to me: June 9, 2003
Date

Brenda C. Albertson
Notary Public

My commission expires: Notary Public, South Carolina, State at Large
My Commission Expires March 6, 2008
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SEAL

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ATTACHMENT 1

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

REQUEST FOR ADDITIONAL INFORMATION
CATAWBA UNITS 1 AND 2
TECHNICAL SPECIFICATION AMENDMENT - STEAM GENERATORS
STRUCTURAL INTEGRITY PERFORMANCE CRITERIA

References:

1. Nuclear Energy Institute (NEI) Letter to NRC dated November 14, 2002, "Steam Generator Structural Integrity Performance Criterion Accident Loading Safety Factor," enclosing "White Paper on Deterministic Structural Integrity Performance Criterion Definition."

2. Duke Energy Letter to NRC dated February 25, 2003, requesting amendment to Catawba Unit 1 and 2 technical specifications regarding steam generators. Accession Number ML030690029.

Background

Section 2.1 of the White Paper enclosed with Reference 1 defines a proposed revision to the steam generator structural integrity performance criterion as provided in NEI 97-06, Revision 1. This revised performance criteria has been incorporated as part of a proposed amendment of the technical specifications for Catawba Units 1 and 2 submitted by Duke Energy Corporation in Reference 2.

Requested Information

1. The proposed revision to the structural integrity performance criteria would limit application of the safety factors of 3.0 and 1.4 to primary to secondary pressure differentials associated with normal steady state full power operation and with Level D service, respectively. Provide technical justification for not applying these safety factors to other sources of primary membrane stress and primary bending stress. This technical justification needs to address the consistency of this proposal with safety factors invoked in Section XI of American Society of Mechanical Engineers (ASME) Boiler

and Pressure Vessel (B&PV) Code flaw analyses for primary membrane and primary bending stress for other components and justify differences. In addition, this technical justification needs to specifically address the safety factors used in Section XI of the Code for evaluation of flaws in austenitic piping, and discuss why these safety factors, which presumably apply to non-pressure related sources as well as pressure related sources of primary membrane stress and to primary bending stress, are not appropriate for application to steam generator tubes. (Note, the safety factors in Appendix C of Section XI applicable to primary membrane plus bending stress are 2.77 for normal operating conditions and half that for emergency and faulted conditions. The 2.77 safety factor represents an average of a factor of 3.0 derived from Section III of the Code for primary membrane stress and a factor of 2.55 derived from Section III for primary bending stress. (Reference: EPRI NP-4690-SR, "Evaluation of Flaws in Austenitic Steel Piping")

Duke Energy Corporation Response:

The historical reference for the safety factors used for tube structural integrity criterion is NRC Regulatory Guide (RG) 1.121, which applies a factor of 3.0 and 1.4 on tube burst. The basis for these factors is the ASME Section III design margins implied from the primary membrane stress allowables. For full power steady state operation, the dominant primary loads are due to differential pressure, which will only create a membrane stress condition in the tube. For accident loads, there is another set of requirements for combined primary and secondary loads as discussed in the response to RAI 4 and 5.

In addition, tube integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, cooldown, and upset conditions) is maintained by the stipulation in the guidelines that degraded steam generator tubes not be stressed beyond the elastic range of the tube material for all primary loads under these conditions. In this context, tube integrity for all expected operating scenarios is demonstrated if the

associated primary membrane stresses are below the yield strength of the tube material for all Service Level A and B (normal and upset) conditions. As it is not practical to verify a yield strength criterion in a field application of the condition monitoring process (e.g., in-situ pressure testing), industry has typically applied safety factors and a specified definition of burst to ensure the yield strength criterion is satisfied and that structural integrity is demonstrated. Assuring a safety factor of 3.0 against burst under normal steady state full power operation primary to secondary pressure differential is a sufficient requirement to also prevent yielding during normal and upset transients. Therefore, the structural integrity criterion is simple in application and ensures that the overall tube integrity is maintained for all normal operating and upset conditions. Tube integrity can be easily verified through condition monitoring, either by calculation or in-situ pressure testing, with little ambiguity.

With regard to ASME Section XI, there are no explicit acceptance criteria that cover steam generator tubes. However, for other areas of the primary pressure boundary, ASME Section XI imposes flaw acceptance criteria based on similar reference back to the Code of construction. For steam generator tube integrity, as with ASME Section XI flaw evaluation for piping, the fundamental basis for acceptance criteria is satisfying the intent of the ASME design allowables. Hence, the selection of integrity margins to be used for the structural integrity performance criterion for steam generator tubes is consistent with the basis for determining the structural factors used in ASME Section XI flaw evaluation rules for piping and components.

Technical Basis

The Section XI flaw acceptance criteria for piping were established specifically to address the design conditions for piping items. Steam generator tubes have generally been evaluated using the requirements ASME Section III, NB-3200 (Class 1 vessel design rules). Also, the design/equipment specifications for some of the tube repair products (like sleeves) use NB-3200 as the appropriate design requirements. Further, RG 1.121 refers directly to NB-3225 when defining the margins that must be maintained for evaluation of accident loading. NB-3225 simply refers the user to the rules of Appendix F. Hence, vessel design rules seem the most appropriate for defining margins for tube integrity.

Unlike steam generator tubes, the dominant loads for piping are bending moments resulting from dead weight, thermal expansion, and seismic loads. The safety factors of 2.77 (normal operation) and 1.39 (accidents) are applied to the combined primary membrane plus bending stress in a manner where the emphasis of the applied factors is biased toward the bending contribution to the total stress. Furthermore, for evaluation of flaws in wrought austenitic piping material, the thermal expansion stresses are ignored because they will not significantly affect plastic collapse condition of the pipe under bending rotation. At incipient plastic collapse, the individual safety factor on membrane stress will be a variable and will approach unity as the ratio of bending to membrane stress goes to zero. For this reason, the limit load analysis for piping is restricted to the application when $P_b/P_m \geq 1.0$. This will not cover cases for steam generator tubes. In the most recent revisions to Appendix C, a membrane stress limit of σ_m^c/SF_m has been included, where σ_m^c is the membrane stress at incipient failure and SF_m is the structural factor equal to 2.7 for Level A loads, and 1.3 for Level D loads, to address pressure dominant cases that can occur in some piping systems. The safety factors of 3.0 and 1.4 on primary membrane load for steam generator tubes are more conservative than these limits for Class 1 piping.

From the above discussion, the direct use of piping evaluation rules from Section XI Appendix C is not appropriate for steam generator tubes. The significant primary loads in steam generator tubes are from differential pressure and are membrane in nature. Primary and secondary bending loads are small and in most cases insignificant to affect adversely the tube burst strength. Secondary axial membrane loads will also exist in some steam generator designs. Non-pressure axial membrane loads are not considered in evaluation of wrought austenitic pipe; however, they can be important to steam generator tube integrity.

From a Section XI precedent, a more appropriate reference for integrity would be the prevention of non-ductile failure for reactor coolant system components given in Appendix G. Appendix G determines the pressure-temperature heatup/cooldown curves for the reactor coolant system and is based on a fracture mechanics assessment method assuming an end of period limiting flaw. In this assessment, primary

stresses are multiplied by a safety factor of 2.0, and secondary stresses are included with a safety factor of 1.0. The safety factors for tube integrity meet or exceed the analysis conditions for other components contained in the primary system to include the reactor pressure vessel and main loop piping.

In summary, the structural integrity performance criterion is based on loading definitions and an evaluation framework consistent with the ASME Code and past regulatory guidelines. The imposition of the stated safety factors and conditions for analysis are sufficient to meet the integrity requirements of RG 1.121.

2. The proposed revision of the structural integrity performance criteria makes the 1.4 safety factor applicable to ASME, Section III Level D loads rather than to "limiting design basis accidents." What design basis accidents could potentially, depending on the plant, not be included among the Level D loads? Provide justification for not including, as part of the proposed change, the appropriate safety factor to be applied to ASME Section III, Level C loads or, alternatively, for not taking the approach described in Section XI, Appendix C of the Code for austenitic piping which is to apply a single safety factor for Level C and Level D loads.

Duke Energy Corporation Response:

The structural performance criterion for accident events was written to satisfy the intent of RG 1.121. It was the intent of RG 1.121 to impose a margin against tube failure under postulated accident conditions consistent with the stress limits of Paragraph NB-3225 of ASME Section III. This Code requirement only covers faulted loads (i.e., Service Level D events). It was apparent that NRC staff guidance for tube integrity was focused on faulted conditions directly affecting the steam generators such as loss of coolant accident, steam line break, or feedwater line break. ASME Section III, Appendix F, which is for analysis of faulted load conditions, provides the basis for the 1.4 factor, derived from the allowable Level D limit of 0.7 S_u. As mentioned in the White Paper, the accident event with the largest differential pressure will fall under the

Level D category. By excluding Level C loads, the criterion will still capture the limiting accident event while keeping the definition of safety factor clear.

Proposed Resolution

Because of the NRC's concern that not referring to all accidents will leave the impression that the design basis may not be satisfied, the criterion will be revised to include all design basis accident events. A safety factor of 1.4 on differential pressure will be used for the accident event determined to be the limiting event.

Technical Basis

The use of a single margin factor for accident conditions (i.e., Levels C and D) has precedent in the Code. ASME Section XI flaw evaluation acceptance criteria for Class 1 vessels impose a structural factor of $\sqrt{10}$ for normal and upset conditions, and a structural factor of $\sqrt{2}$ for emergency and faulted loading conditions. These requirements cover the reactor pressure vessel and other Class 1 components. Design rules for these components are the bases for the structural performance criterion for steam generator tubing. It is therefore appropriate that a single margin factor be used in the evaluation of degraded steam generator tubing for the postulated accidents, since this practice has been used for the evaluation of degraded primary pressure boundary components.

If one were to also consider the other accident conditions classified as Service Level C (emergency loading condition), the design rules for elastic analysis of Service Level C permit the allowable stress to be the greater of 1.8 S_m or 1.5 S_y. On an equivalent basis to S_u, the allowable stress is in the range of 0.6 S_u to 0.66 S_u, which is comparable to the faulted stress limits in Appendix F (0.7 S_u).

Alternatively, a plastic analysis is permitted under NB-3224 for application to Service Level C conditions. Guidance for plastic analysis is given in NB-3228. The allowable stress is derived from the calculated collapse load. This relaxation in the elastic analysis criteria is directly relevant to steam generator tubing, since the basis for tube integrity is burst conditions verified by industry data of pulled tubes and experimental testing for predicting failure (i.e., net-section plastic collapse). Under this Code application, the 1.4 margin on primary membrane load for

accident conditions would be a reasonable and conservative bound for emergency conditions.

3. The intent of the last sentence of the proposed criterion is unclear. Clarify specifically what is meant by the words "appropriate load due to the defined pressure differential." (This appears to be an attempt to capture the intent of the words in the second paragraph of Section 5.3.1 of the White Paper but, in the staff's opinion, doesn't actually do so.) Also, the sentence appears incomplete since it says to combine loads but does not say for what purpose.

Duke Energy Corporation Response:

The phrase "appropriate load due to the defined pressure differential" was intended to impose the requirement that non-pressure loads that are determined to be significant are to be combined with pressure loads. That is, all contributing loads from pressure and non-pressure sources are to be evaluated together (not individually), in order to assess tube integrity for burst under the combined conditions. The "defined" pressure load will depend on the type of tube degradation being assessed and the specific accident event under evaluation.

Section 5.3 of the White Paper discusses which non-pressure loads may be contributing to tube burst for either circumferential or axial degradation. It is clear that axial tube loads will affect tube burst when circumferential degradation is present. It was the intent of Section 5.3.1 to provide guidance for identifying loading conditions and establishing structural limits relevant to circumferential flaws. Similarly, Section 5.3.2 covers axial degradation.

Proposed Resolution

The criterion has been re-written to clarify the meaning of combining loads for the situation when non-pressure contributing loads are determined to be significant. The White Paper will be revised to clarify the guidance on combining loads. The discussion will be expanded to cover seismic loads in order to address the situation for those plants required to combine accident conditions as part of their licensing basis. This guidance will ultimately be included in the main body of the EPRI Tube Integrity

Guidelines document, which is currently undergoing a revision.

4. Provide the technical basis for the proposed safety factor of 1.0 to be applied to non-pressure related primary membrane stress and primary bending stress and cite examples where such safety factors are allowed for other ASME Class 1 components in the ASME Code, other specifications, or in NRC regulatory requirements. Does the proposed safety factor of 1.0 mean that it is acceptable for steam generator tubes to be at the point of incipient plastic collapse or burst? If not, why not and how much actual safety margin is there to burst? (If the response to this question relies on the safety factors being applied to the pressure loads, the response should also address situations where the non-pressure related primary membrane stress and/or primary bending stress may reach their maximum values at a time when the pressure loadings are relatively low.)

Duke Energy Corporation Response:

Contributing non-pressure primary loads during accident conditions would be those axial loads resulting from dynamic conditions. In most situations, the inertia loads on tubes are very low. In particular, primary membrane loads will be negligible. Dynamic tube loads, in and of themselves, will not be major contributors to tube burst. In general, peak loads are short in duration and do not occur at the same time peak pressure differentials are created. Therefore, tube burst will be controlled by the largest differential pressure conditions. If a transient analysis is used to calculate the magnitude of pressure and non-pressure contributing loads, then a time history would be evaluated to capture the time during the event that defines the limiting condition for tube integrity.

Given the above discussion, the use of a safety factor of 1.0 for all contributing non-pressure loads for accident events was proposed as a way to keep the analysis for combined loads simple and straightforward, since only a single factor would be used. Upon further consideration, a separate safety factor on primary loads seems appropriate

following the design requirements of ASME Section III, Appendix F. From these requirements, a safety factor of 1.2 was derived for all sources of primary membrane plus bending loads. The criterion statement has been revised to reflect this change.

Technical Basis

The basis for the structural integrity performance criterion for primary membrane stress for the design basis accidents is ASME Section III, Appendix F, as previously discussed. Appendix F defines a margin on primary membrane stress of 1.4 derived from the allowable Level D limit of 0.7 S_u. Therefore, imposing a safety factor of 1.4 on primary membrane load will preserve the elastic stress limits provided by the Code.

For the case of combined primary membrane plus bending, the Appendix F collapse method was used to define acceptance for tube integrity. When an analysis is performed to ASME Section III, NB-3200, the evaluation of accident loads may be performed in accordance with the rules of Appendix F. Acceptance criteria for elastic system analysis are covered in Article F-1331.1(c)(2) and Article F-1341.3 covers plastic system analysis. Both methods and acceptance limits are essentially the same. Appendix F Subsections F-1331.1(c)(2) and F-1341.3 define the allowable stress for the analysis of collapse as 90% of the calculated collapse load where the critical net-section stress is not to exceed the lesser of $2.3S_m$ or $0.7S_u$. Therefore, an analysis could use this allowable and meet the requirements of the ASME Code. The factor of safety implied from this requirement is 1.11. It is apparent that the plastic collapse analysis has different inherent design margins than the one done strictly to the elastic allowable stress limits.

The Code collapse load is the maximum load the tube can take before deformation of the tube will increase without limit. This definition for maximum load is consistent with the industry definition of tube burst condition. When the Appendix F collapse method is applied, a safety factor of 1.2 can be shown to be the resulting factor to be applied to primary loads in an analysis for tube burst.

Determination of 1.2 safety factor (SF) is derived from an equivalency comparison between the load that would be permitted by the Appendix F Code collapse method and collapse load determined by standard industry methods for tube integrity with circumferential degradation:

$$SF = \frac{\text{Calculated Collapse Load}}{90\%\,\text{Accident Collapse Load}} \equiv \frac{\sigma_{Flow}}{0.9\,\sigma_{App.F}}$$

$$\sigma_{Flow} = (\sigma_y + \sigma_u)/2$$

$\sigma_{App.F} = 2.3\,Sm\,or\,0.7S_u$, whichever is less

$$\sigma_y = k\,\sigma_u$$

For Code properties for Alloy 600 and 690,

S_m = 2/3 S_y at RT = 23.3 ksi
S_y = 27.9 ksi, S_u = 80 ksi at 600F (Alloy 600)
S_y = 27.6 ksi, S_u = 80 ksi at 600F (Alloy 690)
k = 0.349 (Alloy 600), 0.345 (Alloy 690)

SF = 0.5(27.9 + 80)/(0.9)(2.3)(23.3) = 1.12

The SF of 1.2 bounds this derivation.

For actual properties for Alloy 600, Table 1 provides the implied SFs for mean properties. A SF of 1.2 bounds the acceptance criteria of Appendix F methods for typical Alloy 600 plant tubing.

With regard to dynamic loads and their contribution to net-section plastic collapse, it has been shown in full size pipe tests that elastically derived loads well above material yield do not result in failure. Proposed revisions to the piping design rules have increased the stress limits from 3.0 S_m to 4.5 S_m or 6.0 S_m depending on imposed loading combinations. Although not yet approved for new plant designs, these revised allowables would permit elastic stress limits to reach 1.5 to 2.0 times the ultimate tensile strength of the material. These limits were determined from pipe test studies.

Table 1 - Alloy 600 Typical Properties - Mean Values

Tubing	RT σ_y, (ksi)	RT σ_u, (ksi)	@Temp σ_y, (ksi)	@Temp σ_u, (ksi)	k	Sm (ksi)	2.3 Sm (ksi)	0.7 σ_u (ksi)	SF
7/8" x 0.050" MA	50.98	99.96	41.89	95.67	0.438	31.9	73.3	67.0	1.14
7/8" x 0.050" TT	48.67	104.72	39.91	94.77	0.421	31.6	72.7	66.3	1.13
3/4" x 0.043" MA	53.05	101.29	45.78	97.35	0.470	32.5	74.6	68.1	1.17
3/4" x 0.043" TT	50.54	105.89	41.50	95.87	0.433	32.0	73.5	67.1	1.14
3/4" x 0.042" MA	41.47	99.64	36.49	94.65	0.386	27.6	63.6	66.3	1.15
3/4" x 0.042" MA	40.27	98.60	35.44	93.67	0.378	26.8	61.7	65.6	1.16
3/4" x 0.042" MA	45.46	102.76	40.00	97.62	0.410	30.3	69.7	68.3	1.12
3/4" x 0.042" MA	46.32	102.77	40.76	97.63	0.417	30.9	71.0	68.3	1.12
3/4" x 0.042" MA	48.60	102.88	42.81	97.73	0.438	32.4	74.5	68.4	1.14
3/4" x 0.042" MA	48.91	102.66	43.04	97.53	0.441	32.5	74.8	68.3	1.14
3/4" x 0.048" MA	45.32	97.50	39.88	92.62	0.431	30.2	69.5	64.8	1.14
3/4" x 0.042" MA	41.73	92.79	36.72	88.15	0.417	27.8	64.0	61.7	1.12
3/4" x 0.048" MA	46.24	97.84	40.69	92.95	0.438	30.8	70.9	65.1	1.14
3/4" x 0.048" MA	46.08	97.03	40.55	92.18	0.440	30.7	70.7	64.5	1.14
5/8" x 0.037" MA	49.69	99.77	41.98	94.61	0.444	31.5	72.5	66.2	1.15
5/8" x 0.037" MA	48.00	99.00	40.60	93.90	0.432	31.3	72.0	65.7	1.14

5. Provide details of the technical basis for the proposed safety factor of 1.0 to be applied to differential thermal loads (the White Paper simply notes that this safety factor is consistent with what has traditionally been used for once through steam generators and is consistent with the Flaw Handbook). The White Paper cites two examples in the Code where thermal stresses are subject to safety factor of 1.0. The staff notes, however, that for certain accidents and transients in once through steam generators (OTSGs), axial thermal stress is dominant axial stress in the tube. Provide assessment of whether there are implicit assumptions made in the development of the two cited examples regarding the relative magnitude of thermal stress compared to other stresses that exists for these examples and whether these assumptions will necessarily be valid for steam generator tubes, particularly those for OTSGs. Does the proposed safety factor of 1.0 mean that it is acceptable for steam generator tubes to be at the point of incipient plastic collapse or burst? If not, why not and how much actual safety margin is there to burst? (If

the response to this question relies on the safety factors being applied to the pressure loads, the response should also address situations where the thermal loads may reach their maximum values at a time when the pressure loadings are relatively low.)

Duke Energy Corporation Response:

The proposed safety factor of 1.0 for differential thermal loads is an industry-established position for all steam generator designs. The White Paper gives a general discussion of secondary thermal loads in Section 3.2, along with the ASME design philosophy for such loads. Axial loads, which are created primarily by the difference in temperature between the tube and shell, are considered a secondary loading per ASME Code definition. By this definition, secondary load (stress) is developed by the constraint of adjacent material or by self-constraint of the structure. The basic characteristic of a secondary stress is that local yielding or deformation will reduce (or eliminate) the load and resulting stress. The thermal load is self-limiting and will not cause failure of the tube or its repair hardware under single load application. Because of the displacement-controlled nature of these loads, the Code allowables for secondary stresses do not contain a safety factor (i.e., safety factor equal to 1.0). The structural integrity performance criterion will be revised to include a definition that contributing loads shall be determined by elastic structural analysis. This clarification is consistent with the intent of the Code design margins and will provide for a conservative evaluation of tube integrity.

Technical Basis

The technical basis for the use of 1.0 factor is discussed in the White Paper. Further, a similar basis is discussed in EPRI NP-4690-SR for the flaw evaluation procedures for austenitic piping. As stated in NP-4690-SR, ASME Section XI flaw evaluation procedures involving austenitic materials recognize that secondary thermal loads are not as important to net-section plastic collapse as are primary loads. Pipe expansion stresses are not considered in the analysis of flaws when materials are ductile (i.e., wrought austenitic materials and non-flux weld metals). For less ductile weld metals and for ferritic materials, expansion stresses are included in the assessment with a safety factor of 1.0.

ASME Section XI reactor coolant system evaluations for pressure boundary integrity, including evaluations of service-induced degradation, consider secondary stresses as being less severe than primary stresses, and generally include them without imposing a safety factor. Therefore, it is appropriate to include contributing axial secondary loads with a safety factor of 1.0 as stated in the structural performance criterion. This practice is consistent with the ASME Code.

6. Discuss whether there need to be stipulations to the use of the proposed safety factor of 1.0 such that it is appropriate for use; e.g., stipulations on the method of analyses used to determine the thermal loads such as the use of elastic analysis. Discuss whether there are circumstances, types of analysis methods, or tests for which different safety factors may be appropriate.

Duke Energy Corporation Response:

The design-by-analysis procedures in ASME Section III are generally based on analysis methods assuming elastic structural response. Therefore, the stress allowable limits, which employ the design margins that form the basis of the burst strength assessments, are to be compared with elastically determined stresses. For statically determinate conditions, such as tubes subjected to differential pressure, the results for tube burst will not depend on the structural response. For secondary loads such as differential thermal loads, the secondary load will be largest under elastic assumptions. Therefore, the proposed safety factor of 1.0 for secondary membrane loads will inherently contain margins against gross failure, since load relaxation and re-distribution occurs concurrent with the onset of yielding. Although not explicitly stated in ASME Section III, elastic stress analysis is the implied analysis method. This implicit assumption is contained in the tube integrity assessment as it pertains to those secondary loads relevant to steam generator tubes.

There are provisions in ASME Section III design to allow the use of non-linear methods to demonstrate Code compliance. These provisions are routinely used when elastic analysis is restrictive (conservative), where local elastic strains become excessive; but permitting a small amount of local (contained) yielding will reduce peak stresses to within

acceptable plastic strain limits. For these situations, elastic-plastic, plastic collapse, and experimental testing are alternate methods of analysis. Allowable limits for these methods will vary depending on load category and Service Level classification, but in general provide an overall relaxation to the allowables for elastic analysis.

In the case of ASME Section III, Appendix F analysis, the collapse load method for limits on primary load may be used for either elastic system analysis or plastic system analysis. Insofar as primary loads are concerned, Appendix F does not restrict its application of collapse load method to the type of analysis that produced the system loads. For the case of secondary loads, the elastic determination of thermal loads would provide for a conservative evaluation for tube burst.

Proposed Resolution

A discussion of analysis methods and assumptions required to apply the structural performance criterion will be included in the Tube Integrity Guidelines document.

REQUEST FOR ADDITIONAL INFORMATION
CATAWBA UNITS 1 AND 2
TECHNICAL SPECIFICATION AMENDMENT - STEAM GENERATORS

B 3.4.13 RCS Operational Leakage (BASES)

1. The licensee proposes to delete a sentence which reads:

   "The volumetric calculation of primary to secondary LEAKAGE is based on a density at operating RCS temperature of 585 degrees F."

   The licensee proposes to add the following statement (Insert B):

   "The primary to secondary LEAKAGE measurement is based on the methodology described in Ref. 5. Currently, a correction factor is applied to account for the fact that current safety analyses take the primary to secondary leak rate at reactor coolant conditions, rather than at room temperature as described in Ref. 5."

   The licensee also proposes to add the following statement (Insert D).

   "The 150 gallons per day limit is based on room temperature measurements."

   The statement in Insert D appears to contradict the statement in Insert B. The licensee needs to resolve this discrepancy. Why should the 150 gallon per day limit not be based on reactor coolant conditions assumed in the current safety analyses?

Duke Energy Corporation Response:

Primary to secondary leak rates at Catawba are measured at room temperature and then multiplied by a correction factor. The adjusted values then correspond to the limiting conditions assumed in the current analyses of radiological consequences of the germane design basis accidents as noted in INSERT B. INSERT D has been revised to make it consistent with INSERT B.

Duke Energy Corporation is presently in the process of re-baselining the Catawba dose analyses for various accidents. The re-baselining effort will include revised analyses of radiological consequences of design basis accidents for which the paths of radioactivity releases include primary to secondary leakage. These revised analyses will reference the assumed limiting primary to secondary leak rates specified in the plant TS to standard conditions. When this effort is completed, the correction factor referenced in INSERT B will no longer be necessary.

2. The first sentence of Insert B needs to be clarified as follows:

   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. 6). 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."

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has revised INSERT B to make the indicated correction.

3. The second sentence of paragraph 4 of Insert B oversells the case based on operating experience and needs to be revised. The staff believes the following to be a more defensible position:

   "The operational leakage rate criterion in conjunction with implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures."

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has revised INSERT B to make the indicated correction.

4. Insert D for SR 3.4.13.2 Bases states that "If this SR is not met, compliance with LCO 3.4.18 should be evaluated." This statement should be in the form of a Note to SR 3.4.13.2.

Duke Energy Corporation Response:

This comment is not incorporated. A Note equivalent to the Bases statement would not be a Surveillance Note, but an Actions table Note stating, "Enter applicable Conditions and Required Actions of LCO 3.4.18, "Steam Generator Tube Integrity," for primary to secondary LEAKAGE through any one SG not within limit." Also, the Note is not needed. If SR 3.4.13.2 is not met, Condition B applies. Condition B requires being in Mode 3 in 6 hours and in Mode 5 in 36 hours. Exceeding the operational leakage rate criterion also results in the Steam Generator Tube Integrity LCO not being met and Condition B applies. Condition B requires being in Mode 3 in 6 hours and in Mode 5 in 36 hours. As the same Actions (an immediate shutdown) apply in both specifications, it unnecessarily complicates the specification to include the Note.

3.4.18 Steam Generator (SG) Tube Integrity

1. The proposed LCO, Actions - Condition A, SR 3.4.18.2, and B 3.4.18 create confusion by referring to plugging tubes which satisfy the tube repair criteria. This is contrary to conventional usage whereby satisfying an acceptance limit implies an acceptable condition and needs to be revised. One acceptable approach is to replace the word "satisfying" with the words "failing to satisfy." Another acceptable approach is to refer to "tubes with flaws that exceed the tube repair criteria."

Duke Energy Corporation Response:

The present language of "satisfying" the tube repair criterion is correct for TS usage. The tube repair criterion as stated in the proposed TS is that tubes which contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged. Hence, if the tube imperfection satisfies the 40% criterion, then it

must be plugged. As far as TS usage is concerned, "failing to satisfy" the tube repair criterion means that the 40% limit has not yet been reached and that plugging is not required. Similarly, "exceeding" the tube repair criterion is also inappropriate language, in that the repair criterion is specified on a "greater than or equal to" basis. The concern raised by the NRC stems from the fact that terminology that constitutes "correct" usage in NEI 97-06 and other industry documents is not the same as terminology that constitutes "correct" usage in TS. Since the NRC comment applies to TS usage, Duke Energy Corporation maintains that the convention is correct as presently proposed. No changes are being made to the TS as proposed in the original submittal in this regard.

2. The words "or repaired" needs to be deleted from the LCO, Actions - Condition A, and SR 3.4.18.2.

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has made the indicated corrections.

3. Required Action A.1 uses words similar to SR 3.4.18.1 thereby creating confusion. The BASES makes it clear that "verify" in SR 3.4.18.1 refers to condition monitoring to be performed during an inspection to confirm that tube integrity existed up to that time. In contrast, "verify" in A.1 refers to a forward looking analytical assessment to verify that tube integrity will be maintained until the next inspection. Action A.1 needs to be clarified as follows.

   "Perform assessment to verify tube integrity of the affected tube(s) will be maintained."

Duke Energy Corporation Response:

This comment was not incorporated. Under the recommended Required Action A.1, simply the performance of an assessment, regardless of its result, would satisfy the Required Action.

Obviously, this was not the NRC's intent. The Required Action as written already requires an assessment in order to verify the conclusion. The word "verify" is used hundreds of times in the Improved TS. As stated in NEI 01-03, "Writer's Guide for the Improved Standard Technical Specifications," Section 4.1.7.a, "Where possible, begin each Surveillance Requirement with a verb, e.g., 'Verify.'" Duke Energy Corporation does not believe that the use of the word "verify" in the Surveillance and the use of the word "verify" in the Required Action creates confusion. However, in order to address the NRC comment, Duke Energy Corporation has revised Required Action A.1 to state, "Verify tube integrity of the affected tube(s) is maintained until the next inspection."

4. An NRC notification requirement needs to be added if the licensee fails to plug a tube which fails to satisfy the applicable repair criteria.

Duke Energy Corporation Response:

10 CFR 50.72 and 10 CFR 50.73 specify the types of events and conditions reportable to the NRC for emergency response and identifying plant specific and generic safety issues. During the development of the Improved Standard TS, reporting requirements were reviewed and eliminated if they were covered by other regulatory requirements. This is further discussed in the NRC letter dated October 25, 1993.

NUREG-1022, Rev. 2, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," provides guidance on the reporting requirements of Title 10 of the Code of Federal Regulations, Part 50, Section 50.72 and 50.73. Section 3.2.4, "Degraded or Unanalyzed Condition," of NUREG-1022, discusses the requirements for reporting a seriously degraded principal safety barrier or an unanalyzed condition that significantly degrades plant safety in accordance with 10 CFR 50.72(b)(3)(ii) and 10 CFR 50.73(a)(2)(ii). This section of NUREG-1022 identifies serious steam generator tube degradation as an example of reportable events and conditions under this criterion. This section of NUREG-1022 further indicates that steam generator tube degradation is considered serious if the tubing fails to meet the

structural integrity and accident induced leakage rate criteria.

As such, placing a reporting requirement in the TS to notify the NRC for failure to plug a tube which fails to satisfy the applicable repair criteria is inconsistent with the guidance of reporting required by the TS. Additionally, this notification requirement is in excess of the reporting required by Title 10 of the Code of Federal Regulations.

<u>B 3.4.18 Steam Generator Tube Integrity (BASES)</u>

1. With respect to the BACKGROUND section of B3.4.18, clarifications are needed as indicated in the attached markup.

Duke Energy Corporation Response:

Duke Energy Corporation indicated in the March 27, 2003 meeting with the NRC concerning this license amendment submittal that the Bases for Section 3.4.18 would be revised consistent with proposed TSTF-449. Accordingly, the B 3.4.18 Bases are being re-submitted and the NRC comments delineated in the marked-up Bases pages were incorporated where appropriate.

2. With respect to the APPLICABLE SAFETY ANALYSES section of B 3.4.18;

   a. Is feed line break a design basis accident for Catawba Units 1 and 2? If so, it needs to be included in the list of design basis accidents in the third paragraph of this section.

Duke Energy Corporation Response:

For Catawba, the feedwater line break accident does not result in a source term release; therefore, the results of this accident are bounded by the results of other accidents listed in Bases B 3.4.18. Accordingly, no changes are required in conjunction with this comment.

   b. The eighth paragraph in the Applicable Safety Analyses Bases states that "the three SG performance criteria and the limits included in the plant Technical Specifications for Dose Equivalent I^{131} in primary coolant and secondary coolant ensure that plant is operated within its analyzed condition." The specific TS needs to be listed to be consistent with the rest of the Bases instead of the generic statement.

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has made the indicated change.

c. The paragraph continues with the statement that "the dose consequences resulting from the most limiting design basis accident are within the limits defined in GDC 19, 10 CFR 100 or the NRC approved licensing basis." This is a very generic statement and it is not clear which limit (GDC 19, 10 CFR 100, or NRC approved licensing basis) is met for Catawba. This needs to be clarified. This comment also applies to the first paragraph under the heading "Design Basis" on page B 3.4.18-7.

Duke Energy Corporation Response:

This comment was not incorporated. The statement referring to GDC 19, 10 CFR 100, or the NRC approved licensing basis is correct as written. The paragraph is discussing a number of design basis accidents and transients which may have different acceptance criteria (e.g., some may have 10 CFR 100 and some may have other NRC approved dose limits). As this paragraph does not establish requirements for the accident analysis, but merely summarizes the relevant events for these limits, the general discussion of acceptance limits is appropriate.

3. With respect to the LCO section of B 3.4.18;

a. The first 4 paragraphs of this section are intended, in part, to summarize those actions necessary to ensure compliance with the LCO for SG tube integrity.

These paragraphs need to be clarified as indicated in the attached markup to distinguish those actions specifically cited by Specification 5.5.9, "Steam Generator Program," versus those that are not specifically spelled out in the specification but which the licensee is performing as part of the SG program consistent with industry guidance.

Duke Energy Corporation Response:

As indicated in a previous comment response, Duke Energy Corporation has revised the B 3.4.18 Bases to be consistent with proposed TSTF-449. The level of detail included in TSTF-449 and the revised B 3.4.18 Bases is consistent with the level of detail provided in the Bases for other TS sections. This comment proposes the addition of material which is outside the scope of the Bases LCO section; therefore, this comment was not incorporated.

b. There is a subheading within this section (on page B 3.4.18-6) entitled "Tube Structural Integrity." This sub-heading needs to be revised since burst integrity is discussed earlier in the section. "No Yield Criterion" or "Yield Strength Considerations" are more appropriate headings.

Duke Energy Corporation Response:

The proposed revised Bases for B 3.4.18, which are consistent with proposed TSTF-449, no longer contain this subsection.

c. At the bottom of page B 3.4.18-8, there is a paragraph which reads:

"The Bases for SR 3.4.13.2 indicates that if this SR is not met, compliance with LCO 3.4.18 should be evaluated. If SR 3.4.13.2 is met, then compliance with LCO 3.4.18 need not be evaluated insofar as primary to secondary LEAKAGE is concerned."

The second sentence needs to be clarified to refer to primary to secondary <u>operational</u> LEAKAGE.

A third sentence needs to be added to the paragraph to emphasize the point that the integrity of tubes found to be leaking during SG tube inspections need to be evaluated as part of condition monitoring against the tube structural integrity and accident leakage performance criteria in accordance with the SG program, even if the operational leakage criterion was satisfied immediately prior to plant shutdown.

Duke Energy Corporation Response:

The revised B 3.4.18 Bases no longer contain the paragraph which is the subject of this comment; therefore, this comment was not incorporated.

4. With respect to the ACTIONS section of B 3.4.18;

   a. Confusion is created by referring to plugging tubes which satisfy the tube repair criteria. This is contrary to conventional usage whereby satisfying an acceptance limit implies an acceptable condition and needs to be revised. One acceptable approach is to replace the word "satisfying" with the words "failing to satisfy." Another acceptable approach is to refer to "tubes with flaws that exceed the tube repair criteria."

Duke Energy Corporation Response:

This comment was already addressed in the response to a similar previous comment.

   b. The words "or repaired" appear here and in other sections of B 3.4.18. These words need to be deleted consistent with staff comments that words relating to tube repairs should be deleted from Specifications 3.4.18 and 5.5.9.

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has made the necessary deletions.

c. The last sentence of second paragraph under sub-heading "A.1 and A.2" states that "the tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered." This statement is incomplete. The following words need to be added to the end of the sentence: "and estimated growth of the degradation prior to the next SG inspection."

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has made the necessary addition.

5. With respect to the SURVEILLANCE REQUIREMENTS section of B 3.4.18;

    a. The first paragraph needs to be clarified as indicated in the attached markup to distinguish those actions specifically cited by Specification 5.5.9, "Steam Generator Program," versus those that are not specifically spelled out in the specification but which the licensee is performing as part of the SG program consistent with industry guidance.

Duke Energy Corporation Response:

As indicated in a previous comment response, Duke Energy Corporation has revised the B 3.4.18 Bases to be consistent with proposed TSTF-449. The level of detail included in TSTF-449 and the revised B 3.4.18 Bases is consistent with the level of detail provided in the Bases for other TS sections. This comment proposes the addition of material which is outside the scope of the Bases Surveillance Requirements section; therefore, this comment was not incorporated.

    b. This section of B 3.4.18 states: "The Steam Generator Program determines the scope of the inspection and the methods used to determine compliance with the performance criteria." This sentence misses the point that the inspection scope and methods are used to determine whether the tubes contain flaws exceeding the tube repair criteria. This sentence needs to be revised as follows:

"In accordance with specification 5.5.9, the inspection scope (i.e., number and portions of the tubes inspected) and method 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 and the tube-to-tubesheet weld at the tube outlet, and that may exceed the applicable tube repair criteria. In addition, the scope, method, and frequency of inspection are such as to ensure that steam generator tube integrity is maintained."

Duke Energy Corporation Response:

Duke Energy Corporation has partially incorporated this comment. The subject Bases discussion was changed to reflect the fact that the inspection scope and methods are used to determine whether the tubes contain flaws that satisfy the tube repair criteria. However, the suggested additional material was not incorporated due to the fact that it is nearly an exact duplication of proposed material contained in Specification 5.5.9. It is standard convention in the Improved TS and Bases not to duplicate material in a section which is already contained in another section. The Bases for B 3.4.18 already make adequate reference to Specification 5.5.9, where the proposed material is contained.

c. This section of B 3.4.18 states: "Inspection scope is a function of existing and potential degradation locations and safety/pressure boundary considerations." The words "and safety/pressure boundary considerations" need to be deleted from this sentence. A key objective of tube inspections is to find flaws which may exceed the tube repair limit where ever such flaws may exist along the tube length and whatever their safety implications. Staff comments made elsewhere in this RAI are intended to ensure that Specification 5.5.9 is clear on this point. The staff believes that the entire length of tubing between the welds is part of the design basis pressure boundary. If the licensee believes that certain flaws in certain regions of the tubing have no safety implications even if they exceed the plugging limit, the staff believes that a technical specification amendment is necessary if such flaws are not to be addressed by the inspection scope and/or methods.

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has made the necessary deletion.

d. The last two paragraphs under the heading "SR 3.4.18.1" need to be clarified as indicated in the attached markup to better distinguish those actions specifically cited by Specification 5.5.9, "Steam Generator Program," versus those that are not specifically spelled out in the specification but which the licensee is performing as part of the SG program consistent with industry guidance.

Duke Energy Corporation Response:

Duke Energy Corporation has partially incorporated this comment. Some of the language in the NRC's proposed insert material is inconsistent with language commonly used throughout the Improved TS Bases. The relevant Bases discussion for SR 3.4.18.1 was revised to state that the inspection frequency is determined in part by the operational

assessments and in part by the prescriptive requirements of Specification 5.5.9.

e. The third paragraph under the heading "SR 3.4.18.2" incorrectly states that the tube repair criteria assures that tubes left in service will meet the performance criteria at the next scheduled inspection irrespective of the other elements of the SG Program including the SG inspection interval. This paragraph needs to be revised in a manner similar to the attached markup to make it clear that the tube repair criteria in conjunction with other elements of the SG program assures that tubes left in service will meet the performance criteria at the next scheduled inspection.

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has made the necessary changes, with slight editorial revision.

f. The second to last paragraph on page B 3.4.18-12 and the second full paragraph on page B 3.4.18-13 both address the topic of the significance of failing to detect a flaw which fails to meet the tube repair limit. The first of these paragraphs does not provide an insightful discussion of the topic and needs to be deleted or a more insightful discussion provided. The staff has no objection to the second of these paragraphs.

Duke Energy Corporation Response:

Both of the cited paragraphs have been deleted in the revised Bases B 3.4.18 submitted via this response.

<u>Specification 5.5.9, Steam Generator (SG) Program (Version dated April 25, 2003)</u>

1. The first sentence of the first paragraph requires that an SG program be established and implemented to ensure SG tube integrity

is maintained. The second sentence of the first paragraph states that the SG program shall address the following topics (provisions): a., b., c..... The staff believes that this sentence can be misconstrued to mean that implementation of the listed provisions is sufficient to ensure that SG tube integrity is maintained and, thus, the listed provisions are sufficient to constitute an acceptable SG Program. The specification needs to be clarified to ensure that it is not misconstrued in this manner. To this end, the second sentence of the first paragraph needs to be replaced with the following: "In addition, the SG program shall include the following provisions."

Duke Energy Corporation Response:

Duke Energy Corporation has changed the first paragraph of TS 5.5.9 to state, "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:".

2. Paragraph d of the proposed specification is inappropriate for two reasons and needs to be deleted. First, it creates a potential compliance issue with respect to the second sentence of the opening paragraph of the specification. This second sentence requires, in part, that the SG Program address provisions for repair methods. However, there are currently no repair methods approved for the Catawba steam generators. Thus, there are currently no provisions for repair methods.

   Second, paragraph d would permit the use of repair methods approved by NRC. The paragraph is unclear with respect to whether the approval would need to be specific to Catawba or whether repair methods could be implemented that have been approved for another plant or which have been approved generically. In any case, paragraph d reintroduces a problem that previously existed with the NEI Generic License Change

Package and which was the subject of an NRC letter to NEI dated June 11, 2002. That letter concluded that approved tube repair methods should be identified in the technical specifications based on existing regulations and Agency policy, including the Commission's Perry decision in 1996.

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has deleted all references to repair methods from Specification 5.5.9.

3. Paragraph e of the proposed specification states: "The scope of inspection and method of inspection shall ensure the detection of flaws not meeting the performance criteria that are present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet." The words "scope of inspection" need to be clarified in parentheses as referring to the number and portions of tubes to be inspected. In addition, the words "shall ensure the detection of flaws not meeting the performance criteria" are not consistent with the keystone objective of the SG Program which is to ensure that tube integrity is maintained during Mode 1 through 4 operation. If one only has the ability to detect tubes not meeting the performance criteria, there is no assurance that one can detect flaws in sufficient time to ensure that the performance criteria will be met at the time of the next scheduled inspection.

   Paragraph e of the proposed specification also states: "Inspection intervals shall be based on integrity evaluations from the previous SG inspection and shall not exceed the intervals described below." The intent of the words "integrity evaluations from the previous SG inspection" is vague. These words do not directly relate inspection interval to the need to ensure that tube integrity is maintained.

In addition, paragraph e states: "SG inspection intervals shall be as follows:" This sentence is inconsistent with the earlier sentence unless it is modified to indicate that these are additional requirements.

The staff believes that paragraph e. needs to be revised as follows:

e. "Periodic steam generator tube inspections shall be performed. The inspection scope (i.e., number and portions of the tubes inspected) and method 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 and the tube-to-tubesheet weld at the tube outlet, and that may exceed the applicable tube repair criteria. (The tube-to-tube sheet weld is not part of the tube.) In addition to meeting requirements e.1, e.2, and e.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that steam generator tube integrity is maintained until the next SG inspection."

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment, except that the paragraph numbers have been changed to d.1, d.2, and d.3. In addition, the following sentence was added to paragraph d: "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 what inspection methods need to be employed and at what locations."

4. The words "by bobbin coil eddy current technique" in sub-paragraph e.1 needs to be deleted. The staff doesn't wish to endorse the bobbin coil inspection method as being sufficient during the first inservice

inspection. It would be the licensee's responsibility, as it is now, to perform a degradation assessment prior to the inspection in accordance with NEI 97-06 to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine what inspection methods need to be employed and at what locations.

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has removed the reference to bobbin coil eddy current technique.

5. The April 25 version of the licensee's proposed specification adds additional words to sub- paragraph e.2 and e.3 as follows: "However, during the first inspection period, examination of regions susceptible to stress corrosion cracking (e.g., expansion transitions, nonstress-relieved low-row U-bends, dents, dings) may be limited to 20% of the tubes in each SG at the refueling outage nearest the midpoint of the period and an additional 20% at the refueling outage nearest the end of the period." The staff notes that these proposed additional words could be interpreted to mean that inspection intervals for locations subject to stress corrosion cracking could exceed the 48 EFPM/2 fuel cycle limitation for Alloy 600 TT tubing and the 72 EFPM/3 fuel cycle limitation for Alloy 690 TT tubing. For example, the additional wording implies that an inspection interval of 54 EFPM is acceptable for stress corrosion cracks for plants with Alloy 600 TT tubing and operating with 18 EFPM fuel cycles. The proposed additional words need to be deleted.

   The parenthetical expression "(whichever is sooner)" needs to be added to the last sentence of e.2 and e.3 and to the first sentence of e.4.

Duke Energy Corporation Response:

Duke Energy Corporation has deleted the sentence. It was the intent of the sentence to do exactly what the NRC stated. It is expected that an assessment of degradation be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine what inspection methods need to be employed and at what locations.

Duke Energy Corporation concurs with the second part of this comment and has added the phrase, "whichever is less" to the appropriate locations.

6. There was no item 6 in the Request for Additional Information.

7. The Bases of TS 3.4.4, 3.4.5, and 3.4.6, describes an Operable RCS loop as having "an operable RCP and an operable SG in accordance with the Steam Generator Program." The Bases of TS 3.4.7 states that "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 Program." The proposed Steam Generator Program does not describe what an Operable SG is (i.e., there is no statement that says that an operable SG is ...). The Steam Generator Program needs to state what is an OPERABLE SG.

Duke Energy Corporation Response:

Duke Energy Corporation agrees that there is an inconsistency between the Bases and the SG Program. However, a better resolution is to change the Bases instead of the SG Program. The suggested second sentence to 5.5.9, "The steam generators are OPERABLE when steam generator tube integrity is maintained." is incorrect. In order to satisfy the definition of operability, a system, subsystem, train, component, or device must be capable of performing its specified safety function(s) and all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified

safety function(s) must also be capable of performing their related support function(s). For a SG to be operable, it must be capable of performing all functions assumed in the safety analysis for the applicable condition. This includes tube integrity, but may also include requirements such as the ability to remove heat, necessary instrumentation, appropriate seismic supports, etc. Duke Energy Corporation has revised the applicable Bases statements to delete reference to the Steam Generator Program insofar as SG operability is concerned. The specifics as to what is required for the SGs to be operable are left to the definition of operability, as is done for RCPs.

8. The proposed SR 3.4.13.2 requires that verification that primary to secondary leakage is less than or equal to 150 gallons per day through any one steam generator. This verification is to be performed at a frequency "in accordance with the SG Program." The staff acknowledges that the proposed B 3.4.13 states that leakage will be monitored in accordance with industry guidelines for the SG Program which include detailed guidelines for monitoring primary to secondary leakage. However, proposed Specification 5.5.9, "Steam Generator Program" makes no specific mention of verifying that operational primary to secondary leakage meets the specified limit. To ensure the proposed specification meets the intent of 10 CFR 50.36, the following additional provision needs to be included in 5.5.9.

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has made the necessary addition.

The attached sample specification 5.5.9 illustrates a revised version of the specification submitted by the licensee on April 25, 2003 which addresses the staff's comments above.

TS 5.5.9, Steam Generator (SG) Program:

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. The steam generators are OPERABLE when steam generator 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 and accident induced leakage integrity. The "as found" condition refers to the condition of the tubing during a SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging or repair of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected, plugged, or repaired 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: **Comments will be resolved by a different group**

    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 gallons per day through each SG for a total of 600 gallons per day through all SGs.

    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 or repaired.

d. Provisions for SG tube inspections. Periodic steam generator tube inspections shall be performed. The inspection scope (i.e., number and portions of the tubes inspected) and method 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 and the tube-to-tubesheet weld at the tube outlet, and that may exceed the applicable tube repair criteria. (The tube-to-tube sheet weld is not part of the tube.) In addition to meeting requirements e.1, e.2, e.3, and e.4 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that steam generator tube integrity is maintained until the next SG inspection.

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

2. For Unit 1, inspect 100% of tubes at sequential periods of 144, 108 72, and, thereafter, 60 effective full power months (EFPM). The first sequential period shall be considered to begin after the first inservice inspection of the SG's. In addition, inspect 50% of the tubes by the refueling outage nearest the mid point of the period and the remaining 50% by the refueling outage near the end of the period. No SG can operate for more than 72 EFPM or three refueling outages (whichever is sooner) without being inspected.

3. For Unit 2, inspect 100% of tubes at sequential periods of 120, 90, and, thereafter, 60 EFPM. The first sequential period shall be considered to begin after the first inservice inspection of the SG's. In addition, inspect 50% of the tubes by the refueling outage nearest the mid point of the period and the remaining 50% by the refueling outage near the end of the period. No SG can operate for more than 48 EFPM or two refueling outages (whichever is sooner) without being inspected.

4. 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 EFPM or one refueling outage (whichever is sooner). 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 crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary leakage.

Specification 5.6.8, "Steam Generator Tube Inspection Report"

References to repair methods and repairs need to be deleted.

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has made the necessary deletions. Note also that the time period for submission of the required report has been changed from 120 days to 180 days after the initial entry into Mode 4 following completion of the inspection. This was discussed in telephone conference calls with the NRC.

Specification 3.4.13, "RCS Operational LEAKAGE"

Our review has determined that there is a problem with one area of your application for amendment. The proposed Technical Specification (TS) Surveillance Requirement (SR) 3.4.13.2 requires verification that primary-to-secondary leakage is less than or equal to 150 gallons per day through any one steam generator. The proposed frequency in SR 3.4.13.2 is in accordance with the Steam Generator Program. After review, we have concluded that the frequency must be specified in some fashion, either in the TS itself or by reference in the TS to an NRC approved program or method. Inasmuch as there is no such NRC-approved program or method, it would appear appropriate to specify the surveillance frequency in the TS. Our conclusion is based on the fact that the frequency of a required surveillance is material to the performance of the surveillance. This position is consistent with the staff's Final Policy Statement on Technical Specification Improvements for Nuclear Power Reactors, 58 FR 39132 (July 22, 1993).

Duke Energy Corporation Response:

Duke Energy Corporation concurs with this comment and has revised SR 3.4.13.2 and its Bases to specify a 72-hour frequency for the performance of this SR. Refer to the revised marked-up pages for this SR and its Bases. The net effect of the resolution to this comment is that the frequency for the performance of primary to secondary leakage verification is unchanged from that contained in the existing TS (72 hours).

ATTACHMENT 2

REVISED MARKED-UP TS AND BASES PAGES FOR CATAWBA

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.

Operation in other MODES is covered by:

BASES

LCO (continued)

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, thereby maintaining the margin to criticality. Boron reduction 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 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

BASES

LCO (continued)

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, therefore maintaining the margin to criticality. Boron reduction 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 before the start of an RCP with any RCS cold leg temperature ≤ 285°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 OPERABLE if they are capable of being powered and are able to provide forced flow if required.

BASES

LCO (continued)

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.

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. If not in its normal RHR alignment from the RCS hot leg and returning to the RCS cold legs, the required RHR loop is OPERABLE provided the system may be placed in service from the control room, or may be placed in service in a short period of time by actions outside the control room and there are no restraints to placing the equipment in service. 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 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side

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. ~~576 gallons per day total primary to secondary LEAKAGE through all steam generators (SGs); and~~

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

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS operational 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.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	------NOTES------ 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. ------------------ Verify RCS Operational LEAKAGE within limits by performance of RCS water inventory balance.	------NOTE------ Only required to be performed during steady state operation ------------------ 72 hours
SR 3.4.13.2	~~Verify steam generator tube integrity is in accordance with the Steam Generator Tube Surveillance Program.~~ ------NOTE------ Not required to be performed until 12 hours after establishment of steady state operation. ------------------ Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG.	~~In accordance with the Steam Generator Tube Surveillance Program~~ ------NOTE------ Only required to be performed during steady state operation ------------------ 72 hours

NO CHANGES THIS PAGE.
FOR INFORMATION ONLY

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 plant 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.

10 CFR 50, Appendix A, GDC 30 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

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 is necessary. Quickly 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 that is detrimental to the safety of the facility and the public.

A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

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 analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

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.

BASES

APPLICABLE SAFETY ANALYSES (continued)

INSERT A

The safety analysis (Ref. 3) for an event resulting in steam discharge to the atmosphere assumes a 576 gpd primary to secondary leakage as the initial condition (limited to 150 gpd per SG). Any event in which the reactor coolant system will continue to leak water inventory to the secondary side, and in which there will be a postulated source term associated with the accident, utilizes this leakage value as an input in the analysis. These accidents include the rod ejection accident, locked rotor accident, main steam line break, steam generator tube rupture and uncontrolled rod withdrawal accident. The rod ejection accident, locked rotor accident and uncontrolled rod withdrawal accident yield a source term due to postulated fuel failure as a result of the accident. The main steam line break and the steam generator tube rupture yield a source term due to perforations in fuel pins causing an iodine spike. Primary to secondary side leakage may escape the secondary side due to flashing or atomization of the coolant, or it may mix with the secondary side SG water inventory and be released due to steaming of the SGs. The rod ejection accident is limiting compared to the remainder of the accidents with respect to dose results. The dose results for each of the accidents delineated above are well within 10 CFR 100 limits for the rod ejection accident, and below a small fraction of 10 CFR 100 limits for the remainder of the accidents.

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36 (Ref. 4).

LCO

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 and gaskets 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

INSERT A for B 3.4.13 Applicable Safety Analyses:

that primary to secondary LEAKAGE from each steam generator (SG) is 150 gallons per day

BASES

LCO (continued)

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 576 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.~~

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

INSERT B

~~The 150 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.~~

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.

INSERT B for B 3.4.13 LCO:

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. 6). 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 primary to secondary LEAKAGE measurement is based on the methodology described in Ref. 5. Currently, a correction factor is applied to account for the fact that current safety analyses take the primary to secondary leak rate at reactor coolant conditions, rather than at room temperature as described in Ref. 5.

The operational LEAKAGE rate limit applies to LEAKAGE in any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the LEAKAGE should be conservatively assumed to be from one SG.

The limit in this criterion is based on operating experience gained from SG tube degradation mechanisms that result in tube LEAKAGE. The operational LEAKAGE rate criterion in conjunction with implementation of the Steam Generator Program is an effective measure for minimizing the frequency of SG tube ruptures.

BASES

APPLICABILITY (continued)

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.

or if primary to secondary LEAKAGE is not within limits,

B.1 and B.2

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 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

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. For this SR, the volumetric calculation of unidentified LEAKAGE and identified LEAKAGE is based on a density at room temperature of 77 degrees F. The volumetric calculation of primary to secondary LEAKAGE is based on a density at operating RCS temperature of 585 degrees F.

In order to provide enhanced assurance that the primary to secondary LEAKAGE limit of LCO 3.4.13 is met in MODE 1, a continuous calculation is performed via an Operator Aid Computer program that utilizes the ratio of primary and secondary system activities to determine a LEAKAGE rate. This verification methodology is based on guidance contained in Ref. 5. In addition, on a monthly basis, primary to secondary LEAKAGE is determined based on grab samples.

The surveillance is modified by two Notes.

Note 1 indicates that

The RCS water inventory balance must be performed with the reactor at steady state operating conditions and near operating pressure. 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.

Steady state operation is required to perform a proper inventory balance; calculations during maneuvering are not useful and ~~2~~ Note 1 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.

INSERT C

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."

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

INSERT C for B 3.4.13 Surveillance Requirements:

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.13.2

INSERT D

~~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. 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. EPRI TR-104788-R2, "PWR Primary-to-Secondary Leak Guidelines," Revision 2.
6. NEI 97-06, "Steam Generator Program Guidelines."

INSERT D for B 3.4.13 Surveillance Requirements:

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 LCO 3.4.18, "Steam Generator (SG) Tube Integrity," should be evaluated. The 150 gallons per day limit is based on measurements taken at room temperature, with a correction factor applied to account for the fact that current safety analyses take the primary to secondary leak rate at reactor coolant conditions, rather than at room temperature.

The Surveillance is modified by a Note which states that this SR is not required to be completed until 12 hours of steady state operation near operating pressure have been established. During normal operation the primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling.

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

New TS 3.4.18

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.18 Steam Generator (SG) Tube Integrity

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 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

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met. OR SG tube integrity not maintained.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

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

New TS Bases B 3.4.18

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.18 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

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. SG tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied upon 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 safety functions consistent with their licensing basis, including applicable regulatory requirements.

SG tubing is subject to a variety of degradation mechanisms. SG tubes may experience 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.

BASES

BACKGROUND (continued)

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

APPLICABLE SAFETY ANALYSES

The design basis accidents for which the primary to secondary LEAKAGE is a pathway for release of activity to the environment include the main steam line break, SG tube rupture, reactor coolant pump locked rotor accident, single rod withdrawal accident, and rod ejection accident. The analysis of radiological consequences of these design basis accidents, except for a SG tube rupture, assumes that the total primary to secondary LEAKAGE from each SG initially is 150 gallons per day. Transient thermal hydraulic analyses of these design basis accidents determine the primary to secondary LEAKAGE changes (decreases or increases) that result from changing pressures and temperatures. These calculated values are used in the analyses of radiological consequences of these design basis accidents.

The source term in the primary coolant for some design basis accidents (e.g., reactor coolant pump locked rotor accident and rod ejection accident) is associated primarily with fuel rods calculated to be breached. For other design basis accidents (e.g., main steam line break and SG tube rupture), the source term in the primary coolant consists primarily of the levels of DOSE EQUIVALENT I-131 radioactivity levels calculated for the design basis accident. This, in turn, is based on the limiting values in the Technical Specifications and postulated iodine spikes.

For accidents in which the source term in the primary coolant consists of the DOSE EQUIVALENT I-131 activity levels, the SG tube rupture yields the limiting values for radiation doses at offsite locations. In the calculation of radiation doses following this event, the rate of primary to secondary LEAKAGE in the intact SGs is set equal to the operational LEAKAGE rate limits in LCO 3.4.13, "RCS Operational LEAKAGE." For the ruptured SG, a double ended rupture of a single tube is assumed. Following the initiating event, contaminants in flashed and atomized break flow (the latter computed for time spans during which the tubes are calculated to be uncovered), as well as secondary coolant, may be released to the atmosphere. Before reactor trip, the accident analysis for the SG tube rupture assumes that these contaminants are released to the condenser and from there to the environment with credit taken for scrubbing of iodine contaminants in the condenser. Following reactor trip (and loss of offsite power), the accident analysis assumes that these contaminants are released to the environment through the SG power operated relief valves

BASES

APPLICABLE SAFETY ANALYSES (continued)

and the main steam code safety valves until such time as the closure of these valves can be credited.

For other design basis accidents such as main steam line break, rod ejection accident, reactor coolant pump locked rotor accident, and uncontrolled rod withdrawal accident, the tubes are assumed to retain their structural integrity (i.e., they are assumed not to rupture). The LEAKAGE is assumed to be initially at the limit given in LCO 3.4.13.

The three SG performance criteria and the limits included in LCO 3.4.16, "RCS Specific Activity," for DOSE EQUIVALENT I-131 in primary coolant, and in LCO 3.7.17, "Secondary Specific Activity," for DOSE EQUIVALENT I-131 in secondary coolant, ensure the plant is operated within its analyzed condition. The dose consequences resulting from the most limiting design basis accident are within the limits defined in GDC 19 (Ref. 2), 10 CFR 100 (Ref. 3), or the NRC approved licensing basis (e.g., a small fraction of these limits or 10 CFR 50.67 (Ref. 4)).

SG 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 a 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 (SG) 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 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." 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. 5) and Draft Regulatory Guide 1.121 (Ref. 6).

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than a SG tube rupture, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 150 gallons per day through each SG for a total of 600 gallons per day through all SGs. 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.

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 SG tube rupture under the stress conditions of a loss of coolant accident 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.

BASES

APPLICABILITY

SG tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODES 1, 2, 3, and 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. SG 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 SG tube inspection. 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.

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 outage provided the inspection interval continues to be supported by an operational assessment that reflects the

ACTIONS (continued)

affected tubes. However, the affected tube(s) must be plugged prior to entering MODE 4 following the next refueling outage or SG tube 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.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.18.1. The Frequency is determined in part by the operational assessment and other limits in the Steam Generator Examination Guidelines (Ref. 7). 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 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 5.5.9 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). Ref. 1 and Ref. 7 provide 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 tube inspection ensures that the Surveillance has been completed and all tubes satisfying 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. 10 CFR 50.67.

BASES

REFERENCES (continued)

5. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.

6. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.

7. EPRI TR-107569, "Pressurized Water Reactor Steam Generator Examination Guidelines."

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

INSERT A

~~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:~~

(continued)

INSERT A

5.5 Programs and Manuals (continued)

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 A

5.5 Programs and Manuals

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 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 (Unit 1). The first inservice inspection shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality (Unit 2). 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, 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)

INSERT A

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;

(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 A

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

INSERT A

INSERT A

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. Prompt notification to NRC pursuant to 10CFR50.72 (b)(2)	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. Notification to NRC pursuant to 10CFR50.72 (b)(2)	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 A for TS 5.5.9, Steam Generator (SG) Program:

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 a 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 inservice SG tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cooldown, 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 membrane loads. 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. In the assessment of tube integrity, those loads that do significantly affect burst 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 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 gallons per day through each SG for a total of 600 gallons per day through all SGs.

   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.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and method of inspection shall be performed with the objective of detecting flaws of any type (for example, 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 requirements d.1, d.2, d.3, and d.4 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. For Unit 1, inspect 100% of the tubes at sequential periods of 144, 108, 72, and, thereafter, 60 Effective Full Power Months (EFPM). 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 EFPM or three refueling outages (whichever is less) without being inspected.

3. For Unit 2, inspect 100% of the tubes at sequential periods of 120, 90, and, thereafter, 60 EFPM. 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 48 EFPM or two refueling outages (whichever is less) without being inspected.

4. 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 EFPM 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 crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

14. DPC-NE-2009-P-A, "Westinghouse Fuel Transition Report" (DPC Proprietary).

15. WCAP-12945-P-A, Volume 1 and Volumes 2-5, "Code Qualification Document for Best-Estimate Loss of Coolant Analysis" (W Proprietary).

The COLR will contain the complete identification for each of the Technical Specifications referenced topical reports used to prepare the COLR (i.e., report number, title, revision number, report date or NRC SER date, and any supplements).

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.6 Ventilation Systems Heater Report

When a report is required by LCO 3.6.10, "Annulus Ventilation System (AVS)," LCO 3.7.10, "Control Room Area Ventilation System (CRAVS)," LCO 3.7.12, Auxiliary Building Filtered Ventilation Exhaust System (ABFVES)," LCO 3.7.13, "Fuel Handling Ventilation Exhaust System (FHVES)," or LCO 3.9.3, "Containment Penetrations," a report shall be submitted within the following 30 days. The report shall outline the reason for the inoperability and the planned actions to return the systems to OPERABLE status.

5.6.7 PAM Report

When a report is required by LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6.8 Steam Generator (SG) Tube Inspection Report

INSERT B

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

(continued)

5.6 Reporting Requirements

5.6.8 Steam Generator Tube Inspection Report (continued)

INSERT B

~~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.~~

~~c. The results of inspections of steam generator tubes which fall into Category C-3 shall be reported to the NRC within 30 days prior to the restart of the unit following the inspection. This report shall provide a description of the tube degradation and corrective measures taken to prevent recurrence.~~

INSERT B for TS 5.6.8, Steam Generator (SG) Tube Inspection Report:

If the results of the SG inspection indicate greater than 1% of the inspected tubes in any SG satisfy the SG tube repair criteria specified in Specification 5.5.9, "Steam Generator (SG) Program," a report shall be submitted within 180 days after the initial entry into MODE 4 following completion of the inspection. The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Non-destructive 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, and

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