Nuclear Operating Company
South Texas Project Electric Generating Station P.O. Box 289 Wadsworth, Texas 77483

June 21, 2004
NOC-AE-04001739
10CFR50.90

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
One White Flint North
11555 Rockville Pike
Rockville, MD 20852

South Texas Project
Units 1 and 2
Docket No. STN 50-498 and STN 50-499
License Amendment Request -
Proposed Amendment to Technical Specification 4.4.5.3a

Reference: Letter, T. J. Jordan to NRC Document Control Desk, "Response to Request for Additional Information Regarding Proposed Amendment to Technical Specification 4.4.5.3a," dated March 3, 2004 (NOC-AE-04001678)

Pursuant to 10CFR50.90, STP Nuclear Operating Company (STPNOC) hereby requests an amendment to Technical Specification (TS) 4.4.5.3a, "Steam Generator Surveillance Requirements - Inspection Frequencies." The proposed one-time (per unit) change revises the steam generator inservice inspection frequency requirements in TS 4.4.5.3a for Unit 1 immediately after refueling outage 1RE10 and for Unit 2 immediately after refueling outage 2RE10. The change would allow a 78-month inspection interval after one inspection resulting in C-1 classification, rather than a 40-month interval after two consecutive inspections resulting in C-1 classification. STPNOC notified the NRC of this pending license amendment request in the referenced letter. This change is proposed to eliminate unnecessary steam generator inspections, which will result in significant dose, schedule, and cost savings and preclude mid-loop operations during non-inspection outages.

The Unit 1 steam generators were replaced in May 2000 and the Unit 2 steam generators were replaced in October 2002. The replacement steam generators are the Westinghouse Delta 94 design, which incorporates significant improvements, including Alloy 690 thermally treated tubing.

Attachment 1 to this letter provides the No Significant Hazards Determination and Attachment 2 provides the TS page marked up with the proposed change. There are no changes proposed to the Bases for TS 3/4.4.5, but the Bases are provided in Attachment 3 for information.

The Plant Operations Review Committee has recommended approval of the proposed change. An independent review was performed and approved. STPNOC has notified the State of Texas in accordance with 10CFR50.91(b).

STI: 31755578 A001

STPNOC requests approval of the proposed change by September 30, 2004 to allow timely decisions regarding the scope of refueling outage 1RE12. If SG tube inspections are required for 1RE12, the level 3 schedule, which is due on October 11, 2004, will have to be revised significantly and the contract award process will have to be expedited. These issues could be addressed in a timely manner with an NRC decision date of September 30, 2004.

If there are any questions regarding this proposed license amendment, please contact Mike Berg, Testing and Programs Engineering Manager, at (361) 972-7030 or me at (361) 972-7902.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on June 21, 2004

T. J. Jordan
Vice President,
Engineering & Technical Services

jtc

Attachments:

1. Licensee's Evaluation
2. Proposed Technical Specification Changes (Mark-up)
3. Bases Page (For Information Only)

cc:

(paper copy)

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Attachment 1

Licensee's Evaluation

LICENSEE'S EVALUATION

1.0 DESCRIPTION

This letter is a request to amend Operating Licenses NPF-76 and NPF-80 for South Texas Project (STP) Units 1 and 2. The proposed one-time change (per unit) revises the steam generator (SG) inservice inspection frequency requirements in Technical Specification (TS) 4.4.5.3a after refueling outages 1RE10 and 2RE10 to allow a 78-month inspection interval after one inspection resulting in C-1 classification, rather than a 40-month interval after two consecutive inspections resulting in C-1.

The reason for this one-time change is to eliminate unnecessary SG inspections, resulting in significant dose, schedule, and cost savings and preclude mid-loop operations during non-inspection outages.

STP Nuclear Operating Company (STPNOC) requests approval of the proposed change by September 30, 2004 to allow timely decisions regarding the scope of refueling outage 1RE12. If SG tube inspections are required for 1RE12, the level 3 schedule, which is due on October 11, 2004, will have to be revised significantly and the contract award process will have to be expedited. These issues could be addressed in a timely manner with an NRC decision date of September 30, 2004.

2.0 PROPOSED CHANGE

Currently, TS 4.4.5.3a states, in part:

> 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;
>
> Note: For Unit 1, a one-time inspection interval of a maximum of once per 44 months is allowed for the inspection performed immediately following 1RE10. This is an exception to 4.4.5.3a in that the interval extension is based on all of the results of one inspection falling into the C-1 category.

The proposed change reads:

Note: ~~For Unit 1, a~~ A one-time inspection interval of a maximum of once per 78 ~~44~~ months is allowed for the inspection performed immediately following 1RE10 and 2RE10. This is an exception to 4.4.5.3a in that the interval extension is based on all of the results of one inspection falling into the C-1 category.

3.0 BACKGROUND

The SG tubes have an important safety role because they constitute one of the primary barriers between the radioactive and non-radioactive sides of the plant. The inspection of the SG tubes ensures that the structural integrity of this portion of the reactor coolant system will be maintained. Inservice inspection of SG tubes is essential in order to maintain surveillance of the condition of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of SG tubes also provides a means of characterizing the nature and cause of any tube degradation so that timely corrective measures can be taken.

The Unit 1 SGs were replaced in May 2000 during refueling outage 1RE09 and the Unit 2 SGs were replaced in October 2002 during 2RE09. The replacement steam generators (RSGs) are the Westinghouse Delta 94 design, which incorporates significant improvements, including Alloy 690 thermally treated tubing. The Delta 94 is a scaled-up version of the V. C. Summer Delta 75 RSGs, which have been in service since 1994. The latest 100% bobbin inspection of all three V. C. Summer SGs found no indications of stress corrosion cracking or any active damage mechanisms.

In January 2002, STPNOC proposed a one-time change to revise the SG inservice inspection frequency requirements in TS 4.4.5.3a after refueling outage 1RE10 and 2RE10 to allow a 40-month inspection interval after one inspection resulting in C-1 classification, rather than after two consecutive inspections resulting in C-1 (Reference 1). In June 2002, the request was revised to apply to Unit 1 only (Reference 2). The NRC granted the interval extension for Unit 1 in July 2002 (Reference 3). In October 2003, STPNOC submitted an additional request to extend the inspection interval for Unit 1 because the unit had been shut down for almost six months (Reference 4). The NRC approved the 44-month interval in June 2004 (Reference 5.)

In January 2003, South Carolina Electric & Gas requested a 58-month maximum SG inspection interval for the V. C. Summer plant after two inspections resulting in C-1 classification rather than a 40-month inspection interval (Reference 6). The NRC approved that request in October 2003 (Reference 7).

Finally, in February 2003, Duke Power requested approval of the concept that "no SG with Alloy 690 thermally treated tubing shall operate more than 72 effective full power months (EFPM) without being inspected" for Catawba Units 1 and 2 (Reference 8). This request was included with other proposed changes in conjunction with NEI 97-06, "Steam Generator Program

Guidelines" and the NEI Steam Generator License Change Package. STP's requested 78 calendar months is comparable to Catawba's requested 72 EFPM.

4.0 TECHNICAL ANALYSIS

The STP RSGs are the Westinghouse Delta 94 design, which incorporates significant improvements, including thermally treated Alloy 690 tubing. The significant improvements in RSG design were described in detail in Reference 1. The Delta 94 model is a scaled up version of the V. C. Summer Delta 75 RSGs, which have been in service since 1994 for a total of approximately 97.2 EFPM up to their last refueling outage.

The Catawba application specifically noted that their proposed maximum inspection interval of 72 EFPM is based on the historical performance of advanced SG tubing materials. EPRI Report R-5515-00-2 (Reference 9) shows that the performance of Alloy 690 thermally treated tubing is significantly better than the performance of Alloy 600 mill annealed tubing. There are no known instances of cracking in Alloy 690 thermally treated tubes in either US or international SGs.

4.1 Inspection Results from First Outage after Replacement

The results from the first inspection after replacement for Unit 1 (i.e., during 1RE10) were provided in Reference 10 and discussed at length in Reference 1.

During refueling outage 2RE10 following the first cycle of operation after replacement, 100% of the Unit 2 SG tubes were inspected full-length (i.e., from hot leg tube end to cold leg tube end, including the U-bends) with eddy current. Approximately 1,700 +Point examinations were also performed. These +Point inspections included 20% of all dings at support plates and dings at anti-vibration bar (AVB) intersections in response to recent industry experience of fabrication damage to one tube in an RSG. Full-depth tube sheet +Point examination of 3% of the tubes in the hot leg of all four SGs was performed to obtain baseline information and to respond to current NRC/industry discussions on tube sheet inspection with bobbin coil only. A 20 % +Point examination of Row 1 U-bends in each of the four SGs was also performed. No defective or degraded tubes were indicated. The complete inspection results have been submitted to the NRC (Reference 11).

Additionally during 2RE10, an upper steam drum visual inspection of the main feedwater and auxiliary feedwater spray cans were performed, along with the support structure for the main feedwater header. No anomalies were found. Sludge lancing of all four SG tubesheets and a FOSAR were also performed.

The following inspection results, along with the improved RSG design and industry experience with thermally treated Alloy 690 tubing, provide the basis for proposing a one-time (per unit) extension of the inspection interval to a maximum of 78 months after one category C-1 classification.

Completed Inspection Scope

Table 1 is summary of the inspection programs conducted during the 2RE10 inspection. The completed Special Interest program reflects the examination of indications whose signals exhibited a change from the pre-service eddy current behavior at the same locations. Table 2 is a summary of the conditions reported by the examination program.

Table 1
2RE10 Inspection Summary

Program	SG A	SG B	SG C	SG D	Total
Bobbin - Full Length	7584	7583	7582	7585	30,334
Row 1 U-bend +Point	16	16	16	16	64
Hot leg Tubesheet +Point	228	228	228	228	912
20% Ding +Point	110	13	107	1	231
Special Interest +Point	184	145	254	138	721

Table 2
2RE10 Indication Summary

Condition	SG A	SG B	SG C	SG D
Absolute Drift Signals (ADS)	0	0	0	1
Bulges	1	1	0	0
Dings or Dents	259	58	225	52
Ding or Dent with a Signal Confirmed to be from a Non-flaw Condition (DNS)	126	90	118	43
Distorted Support Signal	0	0	1	0
Manufacture Buff Marks (MBM)	34	48	29	42
MBM with a Signal Confirmed to be from a Non-flaw Condition (MBS)	51	38	54	69
Non-quantifiable Signals (NQS)	7	18	80	25
Permeability Variations (PVN)	0	0	0	1

No mechanical wear was observed at AVB intersections in any of the four SGs, which is consistent with the experience of other SGs with the same U-bend support system as the STP RSGs. No possible loose part (PLP) indications were reported, but several objects were observed during the Foreign Object Search and Retrieval (FOSAR) process described in more detail below. No wear was associated with these objects. No tubes were repaired during this outage as all in-service tubes exceed the 1989 EPRI Alloy 690 Workshop structural integrity requirements (Reference 12).

No forms of SG tube degradation were identified during the SG tube inspections of refueling outages 1RE10/2RE10. Therefore, the structural and accident leakage performance criteria in NEI 97-06, Rev. 1 are predicted to be met until the SGs are inspected next, which is currently scheduled for 1RE14 (late March 2008) and 2RE14 (late March 2010). This represents a maximum operation interval of approximately 78 calendar months between SG inspections

Foreign Object Search and Retrieval

STPNOC performed foreign object searches in all four Unit 2 SGs after upending during installation and again as part of the pre- and post-sludge lance FOSAR during 2RE10. Retrieval activities were necessary only in SG A and SG B. No foreign objects were observed in the other two SGs. A list of the objects identified and their disposition is provided in Table 3. No tube wear was identified during the eddy current inspection and no eddy current indications PLPs were reported. No known foreign objects have been left in the SGs.

Table 3
2RE10 Foreign Objects

SG	Description	Location
A	Twisted metal material, 1/2" long and 1/8" thick	Hot-leg annulus R115/C44-45
A	Folded metal material, 1/8" wide, 1/16" thick, and 7/8" long	Cold-leg partially in-bundle, R126-127/C86-87
B	"C" shaped metal type material 1/4" wide, 1/4" high, and 1/32" thick	Cold-leg annulus R113/C111
B	"S" shaped metal type material; 1/4" wide,1/32" thick, and 2-¼" long	Hot-leg annulus R89-90/C24-25
B	Circular metal type material; 3/8" diameter and 3/16" thick	In-bundle R92/C78

Steam Generator Tubesheet Cleaning

Sludge lancing was performed in all four SGs during the 2RE10 outage. The process was effective in removing both soft and hard sludge. In addition to the standard top-of-tubesheet

(TTS) process, a center stay rod lancing process was utilized to enhance the removal of deposits directly adjacent to the stay rod in-bundle areas. Table 4 shows the amount of sludge removed from each SG during 2RE10, which indicates a very small sludge accumulation.

Table 4
2RE10 Sludge Removal

SG	Sludge Weight
2A	9 lb, 11 oz
2B	7 lb
2C	6 lb, 5 oz.
2D	3 lb, 12 oz

4.3 Condition Monitoring Assessment

A Condition Monitoring Assessment was performed for both units after 2RE10. This proprietary document provides guidelines for evaluating the condition of the SG tubes based on the inspection results. The results showed that all performance criteria had been met based on full-length bobbin inspection of all of the tubes of all four SGs in both units (i.e., from hot leg tube end to cold leg tube end, including the U-bends).

4.4 Operational Assessment

An Operational Assessment was performed for both units after 2RE10 in accordance with EPRI SG Integrity Assessment Guidelines to evaluate the predicted condition of the SGs after 78 months of operation

One possible damage mechanism that could affect RSG tube integrity is wear from secondary side foreign objects. Sludge lancing was performed on the secondary side tubesheet region of all four SGs during refueling outages 1RE10 and 2RE10. Pre-lancing inspections identified several small (less than 1.5 inch-long) pieces of spiral-wound metal gasket banding in Unit 1 SG A and in Unit 2 SG B. No tube wear had occurred, and the lancing process and FOSAR removed the material. A bounding loose part analysis was prompted by indications of a possible loose part below the sixth hot leg support plate, deep in the bundle of Unit 1 that could not be visually investigated.

The bounding analysis, which applies to both units, assumed a metal gasket banding piece actually was located at the worst SG tube location with respect to tube wear and at the worst orientation to cause tube wear. The loose part was assumed to be a gasket banding piece because similar banding pieces were found on the TTS in SG A and it would be small enough to reach this location. The gap between the tubes is only 0.293 inch and a larger object could not have reached this area deep in the tube bundle.

The assumed worst location was at a tube that exhibits the limiting amplitudes of vibration and cross flow velocity. It was also assumed that the tube had an existing 20% throughwall degradation, which is a conservative limit of wear detection with bobbin examination. Additional conservative assumptions included that the object would remain in the same location (once tube wear began) and that only the tube would experience wear.

This hypothetical wear analysis demonstrated safe operation for the proposed 78-month inspection interval. The results of the 1RE10 and 2RE10 inspection, the bounding analysis, improved SG design, and our Foreign Material Exclusion (FME) Program provide confidence that unacceptable foreign object wear will not occur over the proposed operating period.

South Texas Project meets or exceeds current industry guidelines with respect to primary and secondary water chemistry.

4.5 Industry Data

V. C. Summer

The STP Delta 94 RSGs are scaled-up versions of the V. C. Summer Delta 75 RSGs, which have been in service since 1994 (approximately 97.2 EFPM as of the last refueling outage). The last inspection (October 2000) of the V. C. Summer SGs included 100% bobbin inspection of all three SGs, 332 hot-leg TTS +Point inspections, and approximately 65 special interest +Point inspections. No indications of stress corrosion cracking were present. Three possible AVB wear signals were found which were identifiable at the baseline (pre-service inspection) and a previous inservice inspection. Two were sized at a depth of 9% and one was at 5%. These are projected not to reach plugging conditions for eighteen additional cycles. Lack of wear scar standards in the baseline precludes sizing of these indications as they appear in the baseline. The indications are likely to be fabrication artifacts, but they were conservatively treated as wear by V. C. Summer. A growth rate of 1.7% through-wall per EFPY is calculated with the assumption that these indications are active wear. This information provides reasonable assurance that wear indications will not become structurally significant over STP's proposed 78 months of operation prior to the inspections at 1RE14 and 2RE14.

Inspections of the fifteen thermally treated Alloy 600 tubes in service in the old STP Unit 2 SGs and inspections of the thermally treated Alloy 690 tubes of the lead Delta model SGs at V.C. Summer show that the Delta SGs have not experienced any indications of stress corrosion degradation. Corrosion-related degradation is not expected, particularly not early in the life of these RSGs due to the superior corrosion resistant properties of thermally treated Alloy 690 tubes.

The SG chemistry control programs at V. C. Summer and STP are comparable. Both plants have a deaerator and maintain SG chemistry well within the EPRI guidelines.

Shearon Harris

Recent foreign object wear on three tubes of the Shearon Harris SGs led to the prompt detection of leakage by the plant's defense in depth primary-to-secondary leak monitoring program. Photographs of the foreign object from Shearon Harris do not resemble material seen in the SGs of either STP Unit 1 or Unit 2.

Indian Point Unit 3

The Indian Point Unit 3 RSGs have operated for 95 EFPM without indication of active degradation of the Alloy 690 thermally treated tubing. The STP Unit 1 RSGs are expected to have operated for ~ 68.4 EFPM after a 78-month inspection interval, which is well within the Indian Point operating experience.

Conclusion

Industry data supports the laboratory test results demonstrating the superior performance of thermally treated Alloy 690 tubing compared with mill annealed Alloy 600 tubing. The STP inspection results, along with the improved RSG design and industry experience of thermally treated Alloy 690 tubing, provide the basis for proposing a one-time extension of the inspection interval in each unit to a maximum of 78 months after one category C-1 classification. At 78 calendar months, the STP RSGs will be well within the operating experience of Indian Point Unit 3 (95 EFPM) and V. C. Summer (97.2 EFPM).

4.6 Dose, Schedule, and Cost Impact

If the proposed 78-month SG inspection interval is not approved, the current STPNOC plan is to perform 20% full-length bobbin inspection, 20% TTS +Point, and 20% Row 1 and Row 2 U-bend +Point inspections in all four SGs during 1RE12 and 2RE12. The following dose, schedule, and cost impacts for each unit are predicted assuming this scope:

- Accumulated personnel dose including SG platform setup, manway removal, eddy current inspection, and tube plugging is estimated to be approximately 30.5 person-rem.
- The approximate cost associated with inspecting all four SGs, including contractor craft support, is $ 3,000,000.
- The approximate time to perform the planned inspection of four SGs is seven days from removal of the first manway to reinstallation of the last manway after completion of the inspection.

Steam generator inspections during 1RE10 had to be terminated on several occasions due to eddy current probe and guide tube contamination with cobalt coming from the RSG tube inside surfaces. The SG inspection equipment was very highly contaminated and inspection was terminated to protect inspection personnel from high radiation exposures until the equipment could be replaced. The SG inspections accounted for approximately 37% of the total refueling outage exposure.

Collectively, the approval of a 78-month inspection interval for each unit is expected to eliminate three SG tubing inspections over this period. The total avoided dose would be 90 person rem; the total cost reduction would be $9,000,000; and three front-end and back-end mid-loop evolutions would be eliminated.

5.0 REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration

STPNOC has evaluated whether a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92 as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No

There is no direct increase in SG leakage because the proposed change does not alter the plant design. The scope of inspections performed during 1RE10 and 2RE10, the first refueling outage following SG replacement, exceeded the combined TS requirements for the first two refueling outages after replacement. That is, more tubes were inspected than were required by TS. Currently, neither Unit 1 nor Unit 2 has an active SG damage mechanism and will meet the current industry examination guidelines without performing inspections during the next 78 months. The Condition Monitoring Assessment after 1RE10 and 2RE10 demonstrated that all performance criteria were met during these outages. The Operational Assessment shows that all performance criteria will be met over the proposed operating period.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

Response: No

The proposed change will not alter any plant design basis or postulated accident resulting from potential SG tube degradation. The scope of inspections performed during 1RE10 and 2RE10, the first refueling outage for each unit following SG replacement, significantly exceeded the combined TS requirements for the scope of the first two refueling outages after SG replacement. The inspections already performed exceed those required by the current TS over the proposed 78-month period.

The proposed change does not affect the design of the SG s, the method of operation, or reactor coolant chemistry controls. No new equipment is being introduced and installed and equipment is not being operated in a new or different manner. The proposed change involves a one-time extension of the SG tube inservice inspection interval, and therefore will not give rise to new failure modes. In addition, the proposed change does not impact any other plant system or components.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

Response: No

Steam generator tube integrity is a function of design, environment, and current physical condition. Extending the SG tube inservice inspection interval to 78 months will not alter the function or design of the SGs. Inspections conducted prior to placing the SGs into service (pre-service inspections) and inspection during the first refueling outages following SG replacement demonstrate that the SGs do not have fabrication damage or an active damage mechanism. The scope of those inspections significantly exceeded those required by the TS. These inspection results were comparable to similar inspection results for the same model of RSGs installed at other plants, and subsequent inspections at those plants yielded results that support this extension request. The improved design of the RSGs also provides reasonable assurance that significant tube degradation is not likely to occur over the proposed operating period.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

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

6.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10CFR20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10CFR51.22(c)(9). Therefore, pursuant to 10CFR51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

7.0 PRECEDENTS AND REFERENCES

7.1 Precedents

Braidwood Units1 and 2
Docket No. 50-456 and 50-457
TAC No. MB1226 and MB1227
August 9, 2001

Farley Unit 1
Docket No. 50-348
TAC No. MB4310
September 20, 2002

V. C. Summer
Docket No. 50-395
TAC No. MB7312
October 29, 2003

South Texas Project Unit 1
Docket No. 50-498
TAC No. MC1046
June 8, 2004

7.2 References

1. Letter, J. J. Sheppard to NRC Document Control Desk, "Proposed Amendment to Technical Specification 4.4.5.3a," dated January 28, 2002 (NOC-AE-02001245)

2. Letter, T. J. Jordan to NRC Document Control Desk, "Revised Proposed Amendment to Technical Specification 4.4.5.3a," dated June 20, 2002 (NOC-AE-02001351)

3. Letter, J. L. Minns to W. T. Cottle, "South Texas Project, Unit 1 - Issuance of Amendment on Steam Generator Surveillance Requirements (TAC No. MB3963)," dated July 31, 2002

4. Letter, T. J. Jordan to NRC Document Control Desk, "Proposed Amendment to Technical Specification 4.4.5.3a," dated October 16, 2003 (NOC-AE-03001580)

5. Letter, M. K. Webb to J. J. Sheppard. "South Texas Project, Unit 1 - Issuance of Amendment re: One-Time Extension to Steam Generator Inservice Inspection Frequency (TAC No. MC1046)", dated June 4, 2004 (AE-NOC-04001238)

6. Letter S. A. Byrne to NRC Document Control Desk, "License Amendment Request - LAR 02-2767 Steam Generators - One-Time Exclusion of Inspection Frequency," dated January 14, 2003 (RC-03-0007)

7. Letter, K. R. Cotton to S. A. Byrne, "Virgil C. Summer Nuclear Station, Unit 1 - Issuance of Amendment re: One-Time Extension of the Steam Generator Inspection Frequency (TAC No. MB7312),""dated October 29, 2003

8. Letter, G. R. Peterson, "Proposed Technical Specifications (TS) Amendments, dated February 25, 2003

9. "Experience of US and Froeign PWR Steam Generators with Alloy 600TT and Alloy 690TT Tubes and Sleeves," EPRI Report R-5515-00-2, dated June 5, 2002

10. Letter, T. J. Jordan to NRC Document Control Desk, "Special Report - 1RE10 Refueling Outage Inservice Inspection Results for Steam Generator Tubing," dated January 22, 2002 (NOC-AE-02001254)

11. Letter, J. W. Crenshaw to NRC Document Control Desk, "Special Report - 2RE10 Refueling Outage Inservice Inspection Results for Steam Generator Tubing," dated June 16, 2004 (NOC-AE-04001741)

12. R. G. Aspeden, T. F. Grand and D. L. Harrod, "Corrosion Performance of Alloy 690," EPRI NP-6750-M Proceedings: 1989 EPRI Alloy 690 Workshop, New Orleans, LA, April 12 - 14, 1989

Attachment 2

Proposed Technical Specification Changes

(Mark-up)

SURVEILLANCE REQUIREMENTS (Continued)

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

a. The first inservice inspection following steam generator replacement shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality after the steam generator replacement. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections, 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;

   Note: Inservice Inspection is not required during the steam generator replacement outage.

   Note: ~~For Unit 1, a~~ A one-time inspection interval of a maximum of once per ~~44~~ 78 months is allowed for the inspection performed immediately following 1RE10 and 2RE10. This is an exception to 4.4.5.3a in that the interval extension is based on all of the results of one inspection falling into the C-1 category.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 4.4-2 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 4.4.5.3a.; 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 4.4-2 during the shutdown subsequent to any of the following conditions:

   1) Primary-to-secondary tube leaks (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.4.6.2, or

   2) A seismic occurrence greater than the Operating Basis Earthquake, or

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

   4) A main steam line or feedwater line break.

Attachment 3

Bases Pages

(For Information Only)

FOR INFORMATION ONLY

STEAM GENERATOR BASES

The Surveillance Requirements for inspection of the steam generator tubes ensure that the structural integrity of this portion of the RCS will be maintained. The program for inservice inspection of steam generator tubes is based on a modification of Regulatory Guide 1.83, Revision 1. Inservice inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

The plant is expected to be operated in a manner such that the secondary coolant will be maintained within those chemistry limits found to minimize corrosion of the steam generator tubes. If the secondary coolant chemistry is not maintained within these limits, localized corrosion may likely result in stress corrosion cracking. The extent of cracking during plant operation would be limited by the 3.4.6.2.c limitation of steam generator tube leakage between the Reactor Coolant System and the Secondary Coolant System. Cracks having a primary-to-secondary leakage less than this limit during operation have a reasonably high likelihood of achieving "leak-before-break" conditions. Operating plants have demonstrated that primary-to-secondary leakage as low as 150 gallons per day per steam generator can readily be detected. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged.

Wastage-type defects are unlikely with proper chemistry treatment of the secondary coolant. However, even if a defect should develop in service, it will be found during scheduled inservice steam generator tube examinations. Plugging will be required for all tubes with imperfections exceeding the plugging limit of 40% of the tube nominal wall thickness. Steam generator tube inspections of operating plants have demonstrated the capability to reliably detect degradation that has penetrated 20% of the original tube wall thickness.

Whenever the results of any steam generator tubing inservice inspection fall into Category C-3, these results will be promptly reported to the Commission in a Special Report within 30 days and prior to resumption of plant operation. Such cases will be considered by the Commission on a case-by-case basis and may result in a requirement for analysis, laboratory examinations, tests, additional eddy-current inspection, and revision of the Technical Specifications, if necessary.