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50-287	Oconee Nuclear Station, Unit 3, Duke Power Co.	05000287
50-369	William B. McGuire Nuclear Station, Unit 1, Duke Powe	05000369
50-370	William B. McGuire Nuclear Station, Unit 2, Duke Powe	05000370
50-413	Catawba Nuclear Station, Unit 1, Duke Power Co.	05000413
50-414	Catawba Nuclear Station, Unit 2, Duke Power Co.	05000414

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See Reports

SUBJECT: Submits response to GL 97-06 re degradation to SG internals. Attachment 1 provides background discussion on GL 97-06.

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March 26, 1998

U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

ATTENTION: Document Control Desk

SUBJECT: Duke Energy Corporation
Oconee Nuclear Station - Units 1, 2, and 3
Docket Nos. 50-269, 50-270, and 50-287

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

Catawba Nuclear Station - Units 1 and 2
Docket Nos. 50-413 and 50-414

Response to Generic Letter 97-06

NRC Generic Letter 97-06 (GL 97-06), dated December 30, 1997, required holders of operating licenses for pressurized water reactors to submit information to the NRC regarding degradation of steam generator internals. The Duke Energy Corporation response to GL 97-06 for Oconee, McGuire, and Catawba Nuclear Stations is provided in the attachments to this letter. Attachment 1 provides a background discussion on GL 97-06; Attachment 2 provides the response for Oconee Units 1, 2, and 3; Attachment 3 provides the response for McGuire Units 1 and 2; Attachment 4 provides the response for Catawba Unit 1; and Attachment 5 provides the response for Catawba Unit 2.

A detailed evaluation by the Westinghouse Owners Group has not been completed for the model D5 steam generators installed at Catawba Unit 2. The more detailed evaluation should be completed by the end of May 1998. At this time, Duke will supplement its response to GL 97-06 for Catawba Unit 2 if this is determined to be appropriate.

In its previous response to GL 97-05, dated February 24, 1998, Duke committed to follow the requirements of NEI 97-06, *Steam Generator Program Guidelines*. Consistent with the

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requirements of NEI 97-06, Duke will establish a program to monitor the secondary side steam generator components. This program will be applied to components whose failure could prevent the steam generators from fulfilling their intended function.

Please direct questions on this matter to J. S. Warren at (704) 382-4986.

I declare, under penalty of perjury, that the statements set forth herein are true and correct to the best of my knowledge.

Very truly yours,

M. S. Tuckman

M. S. Tuckman

MST/JSW

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Attachment 1

Duke Energy Corporation Response to Generic Letter 97-06 Degradation to Steam Generator Internals

Background

In response to the issuance of a proposed generic letter (GL) on degradation of steam generator internals, the Nuclear Energy Institute (NEI) formed the Steam Generator Internals Task Force in January 1997. The purpose of the task force was to develop a coordinated industry-wide response to the secondary side degradation issues identified in the proposed GL. Participation on the task force included the Electric Power Research Institute (EPRI), licensees, and representatives of the vendors and owners groups for each domestic steam generator design. The task force developed an action plan.

Each owners group initiated a program to assist its respective owners in assessing the susceptibility of tube damage and loss of decay heat removal capability due to secondary side degradation. An integral component in this assessment was an appreciation of the applicability of the degradation found in the French units to domestic steam generators. EPRI responded to this need and with the assistance of Electricite de France (EdF) developed the report, GC-109558, "*Steam Generator Internals Degradation: Modes of Degradation Detected in EdF Units.*"

The EPRI report provides evaluations of the causal factors involved in the modes of degradation experienced in the French units. The owners groups used this report to gain insights into the applicability of the French experience to their steam generator designs and operating history. NEI transmitted this report to the NRC by letter, dated December 19, 1997. EPRI provided copies directly to the Steam Generator Management Program Technical Advisory Group representatives

In addition to the review of the EdF degradation casual factors, the susceptibility assessments included consideration of design factors; fabrication and manufacturing techniques; plant operating history, including chemistry; plant inspection experience; and related degradation, such as denting. As part of the inspection experience review, the owners groups compiled and assessed collective visual, video and pertinent NDE inspection

experience information. This information further enhanced the owners groups' evaluations regarding the susceptibility to internals degradation.

The NEI task force met with the NRC in May 1997, to gain a better understanding of the safety concerns discussed in the generic letter. As a result of these efforts, the owners groups developed preliminary safety and susceptibility assessments relative to the design and operating history of their fleet. These assessments provided reasonable assurance that degradation of internals has not compromised steam generator tube integrity, or decay heat removal capability.

The industry, through the focused efforts of the NEI task force, has provided guidance and information necessary for licensees to adequately address the potential issues regarding steam generator internals degradation.

GL 97-06, Degradation of Steam Generator Internals was issued to: (1) again alert addressees to the previously communicated findings of damage to steam generator internals, namely, tube support plates and tube bundle wrappers, at foreign PWR facilities; (2) alert addressees to recent findings of damage to steam generator tube support plates at a U.S. PWR facility; (3) emphasize to addressees the importance of performing comprehensive examinations of steam generator internals to ensure steam generator tube structural integrity is maintained in accordance with the requirements of Appendix B to 10 CFR Part 50; and (4) require all addressees to submit information that will enable the NRC staff to verify whether addressees' steam generator internals comply with and conform to the current licensing bases for their respective facilities.

Attachment 2

Duke Energy Corporation Response to Generic Letter 97-06 for Oconee Nuclear Station Units 1, 2, and 3

This response provides the B&W Owners Group (B&WOG) member utilities' information and any Oconee specific information relative to the information requested by the Generic Letter. The B&WOG includes the following plants:

- Arkansas Nuclear One Nuclear Power Plant Unit 1 (Arkansas 1, ANO-1)
- Crystal River Nuclear Power Plant Unit 3 (Crystal River 3, CR-3)
- Oconee Nuclear Power Plant Unit 1, 2, 3 (Oconee 1, 2, 3 ; ONS-1, 2, 3)
- Three Mile Island Nuclear Power Plant Unit 1 (Three Mile Island 1, TMI-1)
- Davis Besse Nuclear Power Plant Unit 1 (Davis Besse 1, DB-1)

RESPONSE TO REQUIRED INFORMATION:

GL 97-06 Required Information, Response Item (1):

(1) Discussion of any program in place to detect degradation of steam generator internals and a description of inspection plans, including the inspection scope, frequency, methods, and equipment.

Response to Item (1) for Oconee Units 1, 2, and 3:

The B&WOG plants as a whole currently have no formal program to inspect/monitor steam generator internals degradation. However, as a result of other steam generator activities, such as sludge lancing and chemical cleaning, a significant number of secondary side inspections have been conducted at each of the B&WOG member plants. Visual inspections have been performed from the lower tubesheet to the upper tubesheet and all tube support plates over a range of effective full power years (EFPY) from pre-service to 17.1 EFPY (the oldest B&W-designed OTSG).

Attachment 2

GL 97-06 Required Information, Response Item (1)(a):

(a) Whether inspection records at the facility have been reviewed for indications of tube support plate signal anomalies from eddy-current testing of the steam generator tubes that may be indicative of support plate damage or ligament cracking. If the addressee has performed such a review, include a discussion of the findings:

Response to Item (1)(a) for Oconee Units 1, 2, and 3:

There is currently no qualified eddy current technique to detect degradation in B&W broached hole tube support plates (TSPs). Current eddy current techniques are, however, considered adequate to detect the presence of tube support plates. The many recent 100% bobbin examinations at the BWOG plants have resulted in no instances of missing TSP indications. All Oconee units have conducted 100% bobbin coil inspections at each of the last refueling outages. The eddy current guidelines were modified to look for the presence of tube support plates, no problems were noted. Therefore, it is concluded that the TSPs are located properly and show no signs of gross degradation. Eddy current techniques are now being developed for the detection and characterization of TSP degradation.

GL 97-06 Required Information, Response Item (1)(b):

(b) Whether visual or video camera inspections on the secondary side of the steam generators have been performed at the facility to gain information on the condition of steam generator internals (e.g., support plates, tube bundle wrappers, or other components). If the addressee has performed such inspections, include a discussion of the findings:

Response to Item (1)(b) for Oconee Units 1, 2, and 3:

Table 1 contains a summary of the secondary side internal inspections performed at each of the B&WOG member plants. This table presents the steam generator, EFPY, date, location, purpose, and results for each internals inspection performed. This table shows that a significant number of secondary side inspections have been conducted at each of the B&WOG member plants. These inspections span from pre-service to 17 EFPY, and include all 15 tube support plates,

the upper and lower tubesheets, and one recent inspection of the upper wrapper welds. These inspections are typically performed in conjunction with cleaning processes or tube repair operations.

As part of the secondary side cleaning processes, pre-cleaning and post-cleaning visual inspections were performed on the secondary side of the OTSGs. These cleaning processes include sludge lancing, chemical cleaning and water slap. The post-cleaning visuals provided the clearest view of the tube support plates inspected, typically the 3rd through 6th, 9th, and 10th support plates. These inspections, which were performed to ensure that the process was effective in removing the deposits, showed no signs of any structural damage to the tube support plates.

In recent years, fiberscopic inspections of the secondary side have been conducted following tube pull operations. These inspections utilize the open path left by the pulled tube to visually inspect the condition of the support plates. Because the tubes are typically pulled from the lower tubesheet, most of the inspections encompassed the lower tubesheet through either the 7th, 8th, or 9th tube support plates. In one case the tube hole was inspected from the upper tube end to the 11th tube support plate as well. None of these inspections have found any tube support plate structural damage.

In 1997, the oldest OTSG (Oconee 1) was visually inspected to determine the condition of the upper wrapper welds. For this inspection, two of the main feedwater nozzles were removed to examine the upper wrapper welds from below. No damage was found as a result of this inspection.

In summary, visual inspections have been performed on the internals of all the B&WOG member utilities' OTSGs. These inspections include numerous inspections of the tube support plates and one recent inspection of the upper wrapper welds. These inspections have found no structural damage to these internal components.

<u>GL 97-06 Required Information, Response Item (1)(c):</u>

(c) Whether degradation of steam generator internals has been detected at the facility, and how the degradation was assessed and dispositioned.

Attachment 2

Response to Item (1)(c) for Oconee Units 1, 2, and 3:

With the exception of the internal AFW header, no degradation of tube support plates, internal support structures, or other internal components that may affect tube integrity has been detected at any B&W-designed plant.

There are two configurations of auxiliary feedwater header assemblies which are used on the steam generators of B&W-designed 177FA plants. The first type uses an external distribution header mounted outside the OTSG with nozzles penetrating the shell and shroud. The second type uses an internal distribution header mounted inside the OTSG. Only two of the operating B&WOG member plants used internal AFW headers, Oconee 3 and Davis Besse 1.

In 1981 and 1982, tube leaks were experienced by Davis Besse 1 and Oconee 3, respectively. As a result of eddy current and visual examinations, it was determined that the internal headers and the brackets which attached them to the wrapper were damaged. This degradation resulted in movement of the internal header during plant operation, which damaged some peripheral tubes. The AFW internal headers were subsequently stabilized and functionally replaced by external headers at these plants. No movement or new indications of tube degradation have been noted at either plant since the internal AFW supply headers were stabilized.

Eddy current examinations of peripheral tubes in the DB-1 steam generators are performed each outage to ensure tube integrity. The internal header is visually inspected in accordance with Technical Specifications every ten years at Davis Besse 1.

Oconee 3 inspected the internal AFW headers as part of a NRC commitment in 1982. In addition, visual examinations were performed during the two subsequent refueling outages and then during the 2nd 10-year ISI outage. Oconee 3 has conducted 100% eddy current bobbin coil inspections since 1995, and has not detected any new degradation of the tubes in the periphery of the steam generators in the areas that are susceptible to damage from movement of the AFW supply header. Another visual inspection is planned for the 3rd 10-year ISI.

Attachment 2

Generic Letter 97-06 Required Information, Response Item 2:

(2) If the addressee currently has no program in place to detect degradation of steam generator internals, include a discussion and justification of the plans and schedule for establishing such a program, or why no program is needed.

Response to Item (2) for Oconee Units 1, 2, and 3:

Prior to issuance of GL 97-06, U.S. nuclear utilities, the Electric Power Research Institute and the Nuclear Energy Institute (NEI) developed an action plan to assess the susceptibility of steam generator internals to secondary side degradation. Based upon this NEI action plan, the B&WOG member utilities have developed a process by which a formal program to detect the degradation of steam generator internals will be developed. This process was started in 1997 and is scheduled for completion by December 1998.

The major tasks that comprise the B&WOG process are discussed below. Preliminary results of the work completed are also presented. All available data from NDE inspections, tube pull evaluations, and secondary-side visual inspections supports compliance with and conformance to the current licensing basis for the B&WOG member utilities.

1.0 Owners Group Degradation Experience

The purpose of this task is to identify any internals degradation detected at operating OTSG plants. This task focuses on internal components that may have an effect on tube integrity, and includes the review of relevant visual and eddy current data.

Preliminary review of secondary side visual inspection data and available eddy current data has shown no generic internals degradation in the B&W plants (Table 1). In fact, the only internals degradation found is related to the internal auxiliary feedwater (AFW) headers. As noted in the response to Question (1)(c), only Davis Besse Unit 1 and Oconee Unit 3 had OTSGs of this design, and these internal AFW headers were stabilized and functionally replaced with external feedwater headers in the early 1980's. No further tube damage associated with the internal AFW header has been

detected during subsequent tube inspections at these two plants.

2.0 Owners Group Degradation Assessment

This part of the process is broken down into subtasks and described below:

Evaluate Susceptibility of OTSG Relative to EdF Experience

The B&WOG member utilities are in the process of assembling and summarizing design documentation relative to steam generator secondary side components for all operating B&W plants. Existing analyses that relate to possible degradation mechanisms are also being collected and summarized. This information is being used to determine the susceptibility of the OTSG to secondary side degradation relative to the experience of EdF plants.

EPRI released GC-109558 "Steam Generator Internals Degradation: Modes of Degradation Detected in EdF Units" in December 1997. According to this document, several types of degradation were found in the EdF steam generator internals. These degradation modes, and the preliminary results of evaluations to determine possible applicability to the OTSG are presented below.

1. Flow assisted corrosion (FAC) of the top TSP at Fessenheim 2 was noted during routine eddy current testing in 1995. This corrosion was determined to be the result of improper placement of hoses during a chemical cleaning performed in 1992. The corrosion is not progressing, and inspections indicate that no other French units have experienced similar attack.

   Four of the seven B&WOG plants have had their steam generators chemically cleaned. The EPRI SGOG chemical cleaning solvent used in these cleanings is a different solvent than the one utilized by EdF. The EPRI SGOG solvent has been put through extensive qualification testing prior to its first application and continues to be tested prior to most applications. FAC has been studied as part of the qualification testing and the flow rates during steam generator cleanings are designed to remain

below the critical FAC rates. All of the piping at Oconee was hard piped to the steam generator to limit FAC and for other process control reasons. Equipment design and process control procedures were also utilized to limit FAC. Post-chemical cleaning visual inspections have shown no TSP degradation at any of the four plants. Oconee units 1 and 2 were cleaned more than 7 EFPY's ago, no adverse conditions have been observed by eddy current or visual inspections since that time. The cleanings at Oconee have been effectively controlled and monitored. This does not appear to be a problem at Oconee.

2. In response to the Fessenheim 2 experience, all other operating units in France with drilled hole carbon steel TSPs, i.e., all units with Model 51A and 51M steam generators, were inspected for TSP damage. Both eddy current and television (TV) visual inspections were performed. Review of inspection data has shown that the ligament cracking was present at the first inspection for which interpretable data is available, i.e., at either pre-service or early in-service inspections. The cracking has not changed with time. It is believed that the cracking is the result of mechanical overload applied to the TSP's during manufacture, shipping or early operation.

   At Oconee, significant design differences between the OTSGs and the model 51 steam generators would indicate that ductile overload of the TSP ligaments on the periphery should not be a problem.

   There is currently no eddy current technique qualified to detect TSP degradation in B&W broached hole TSPs. Currently available non-qualified eddy current techniques indicate that the tube support plates are located properly, and show no indications of degradation. These and other eddy current techniques are now being evaluated for EPRI Appendix H qualification. Also, no TSP degradation has been observed in any of the numerous visual inspections performed over the service lives of the OTSGs (see Table 1).

3. FAC induced thinning of the top TSP has been detected by eddy current and TV in three units

(Gravelines 2, 3, and 4) that operated from startup (in the early 1980s) until recently using ammonia water chemistry. The FAC occurred at the periphery of the TSP at the location of the largest radius U-bends. It occurred mostly on the hot leg side, but some was also observed on the cold leg side. The French concluded that the FAC is associated with ammonia water chemistry.

All of the OTSG plants have operated on All Volatile Treatment (AVT) feedwater chemistry. Early in plant life, the chemistry consisted of condensate polished feedwater treated with hydrazine and ammonia for oxygen and pH control, respectively. Later, the pH control additive was switched to alternate amines, such as morpholine. The objective was to reduce FAC in the balance of plant system piping where such problems had been observed. Based on NDE inspections, tube pull evaluations, and the numerous secondary side inspections listed in Table 1, FAC has not been identified as a damage mechanism in the OTSGs at this time. The primary contributors to FAC: flow velocity, quality, and solution pH, will be evaluated in more depth as part of the B&WOG process.

4. Wrapper drop was detected in 1994 at two steam generators in Blayais 3. The drop occurred because of the failure of the wrapper supports located at the first TSP elevation. Two scenarios for the wrapper drop had been proposed by the French: (1) failure of the supports mainly due to thermal expansion loads developed during transients associated with the use of cold auxiliary feedwater to expedite plant cool-down, aggravated by poor quality of the welds joining the support blocks to the wrapper, and possibly by fatigue induced crack propagation, and (2) failure of the supports mainly due to fatigue cracking of the support to wrapper welds, aggravated by poor quality of the welds and by axial load development by thermal transients.

   The B&W-designed OTSGs have a different wrapper design than the EdF plants with the noted degradation. The wrapper consists of two shells, one upper and one lower, separated by a small gap. At Oconee, the lower wrapper of the OTSGs rest on

the lower tubesheet via support lugs. Therefore, lower wrapper drop is precluded. The upper wrapper is supported by an annular ring which is welded to the shell.

During 1997, the oldest operating B&W-designed plant (Oconee-1) conducted a visual inspection of the upper wrapper assembly, welds, and internal components in the vicinity of the welds. During this inspection, no signs of movement or slippage of the upper wrapper were noted. There was no evidence of damage to the welds or components in the vicinity of the wrapper assembly which would indicate that the wrapper had shifted or dropped. Upper wrapper drop is therefore not considered a significant near-term problem for Oconee. However, during the continuing evaluation of steam generator internals, this potential degradation mechanism will be investigated further.

5. Fatigue cracks emanating from support blocks have been detected in the same two Blayais 3 steam generators that experienced wrapper drop, and in one steam generator of similar design at Blayais 2. The fatigue cracks appear to be the results of flow induced vibration of the wrapper. The French indicate that they are evaluating the possible occurrence of this mechanism at other units and designs, since the root cause of this cracking has not been demonstrated to be Blayais 2 and 3 specific.

   As noted above, inspection of the upper wrapper supports at Oconee 1 did not identify signs of degradation. This potential damage mechanism continues to be evaluated for possible future impact on the OTSGs.

6. In French units, some cases of TSP wedge block cracking have been observed. The causes of the wedge block cracking are believed to be the same as those causing TSP ligament cracking. Also in French units, some tie rod lock welds have been found to be cracked. These cracks are considered to have no safety significance.

   At Oconee, significant design differences between the OTSGs and the model 51 steam generators would

indicate that wedge block cracking should not be a problem.

From visual inspections of OTSGs, no degradation has been noted. However, during the evaluation of steam generator internals degradation, this degradation mechanism will be investigated further.

Assess Susceptibility to Other Potential Damage Mechanisms

Preliminary information indicates that recent internals damage found at the San Onofre Nuclear Generating Station (SONGS) has been attributed to FAC associated with fouling.

The steam generators at SONGS are Combustion Engineering recirculating steam generators which have few design and performance similarities to an OTSG. The concentrating mechanisms, bulk water chemical concentrations, and pH control additives behavior, are variables that are typically different in the two types of steam generators. The B&WOG member utilities are aware of the FAC damage at SONGs, and will evaluate it further as part of the BWOG process.

The objective of this subtask is also to address damage mechanisms which have not yet been observed in operating plants, but which may be possible based on operating experience not considered during original plant design. Structural, chemical, and thermal hydraulic performance experience will be reviewed to identify these potential forms of degradation. Any mechanisms which are identified as requiring further investigation will be identified and additional work will be conducted as appropriate.

3.0 Inspection Requirements and Methodology

Based on the results of section 2, internal components identified as being susceptible to internals degradation which could affect tube integrity will be identified. For each of these components, a recommended inspection scope and methodology to monitor for potential future secondary side degradation will be determined.

4.0 Industry Response

The final deliverable will be a project summary report for the B&WOG member utilities. All areas of the OTSG identified as being potentially susceptible to degradation (if any) will be discussed in the report, along with recommended inspection procedures and frequencies, and disposition criteria.

SUMMARY:

The B&W Owners Group has completed a preliminarily review of EPRI GC-109558, "Steam Generator Internals Degradation: Modes of Degradation Detected in EdF Units" relative to the design and operation of Once Through Steam Generators. For each category of degradation, the B&WOG has concluded that the OTSGs are not significantly at risk for the same degradation in the near term. The future susceptibility of the OTSG to these or other forms of degradation continues to be evaluated as part of the B&WOG process to develop a formal SG internals program.

Table 1 provides a summary of secondary side visual inspections conducted at each B&W-designed plant. The B&WOG concludes that the number of plants that have been inspected and the visual inspection results demonstrate with a high degree of confidence that there is currently no significant degradation of steam generator internals in OTSGs. Currently, two of the B&WOG plants monitor periphery tubes for damage from internal AFW headers. The other B&WOG plants do not have this design feature and thus are not susceptible to this type of steam generator internals degradation.

Based on results to date, it is concluded that no near term inspections of the internals are required, and that compliance with and conformance to the current licensing

bases for the B&WOG member utilities has been maintained. When the program is complete, recommendations may be made for future periodic inspections if needed. These recommendations will be included in a report which will be distributed to all the B&WOG member utilities upon completion of this process.

Oconee concurs with this position that no near term inspections are necessary.

Consistent with the requirements of NEI 97-06 and Duke's commitment to follow the NEI initiative, a program (also considering the B&WOG results) will be established to monitor the secondary-side steam generator components. This program will be applied to components whose failure could prevent the steam generators from fulfilling their intended function .

TABLE 1
B&W-Designed OTSGs
Preliminary Secondary Side Visual Inspection / Work History
(Arranged by EFPY for all B&W-Designed Plants)

Date	OTSG	Inspection Location(s)	EFPY (approx.)	Purpose	Results
February 1970	ONS-1A	LTS-1st TSP	0	Pre-service	Loose parts on LTS; nothing unusual reported.
February 1970	ONS-1B	LTS-1st TSP	0	Pre-service	Loose parts on LTS; nothing unusual reported.
November 1972	ONS-2A	LTS	0	Pre-service	Deposits noted on tubes. No secondary side degradation noted.
November 1972	ONS-2B	LTS	0	Pre-service	Deposits noted on tubes. No secondary side degradation noted.
November 1972	ONS-3A	LTS	0	Pre-service	Deposits noted on tubes. No secondary side degradation noted.
November 1972	ONS-3B	LTS	0	Pre-service	Deposits noted on tubes. No secondary side degradation noted.
June 1982	DB-1A		1.8	Refueling Outage AFW Header	The outer vertical member of the AFW header box was distorted over most of the area viewed from the "x" axis manway. The amount of distortion was estimated to be up to 4-1/2".
June 1982	DB-1B		1.8	Refueling Outage AFW Header	The outer vertical member of the AFW header box was distorted over most of the area viewed from the "x" axis manway. The amount of distortion was estimated to be 4".
November 1976	ONS-1A	UTS-15th TSP	2.0	Leaker Outage	Deposits noted on tubes. No secondary side degradation noted.
April 1977 (Outage 3R)	TMI-1A	15th TSP (uppermost span)	2.0	Inspect tubing between 15th TSP and UTS via Z-axis AFW nozzle.	No secondary side degradation noted.

TABLE 1 B&W-Designed OTSGs Preliminary Secondary Side Visual Inspection / Work History (Arranged by EFPY for all B&W-Designed Plants)					
Date	**OTSG**	**Inspection Location(s)**	**EFPY (approx.)**	**Purpose**	**Results**
December 1976	ONS-1B	UTS-15th TSP	2.1	Leaker Outage	Deposits noted on tubes. No secondary side degradation noted.
December 1976	ONS-2B	UTS-15th TSP	2.1	Leaker Outage	No secondary side degradation noted.
November 1977	ONS-3A	FW Nozzles	2.1	Refueling Outage	No secondary side degradation noted.
November 1977	ONS-3A	UTS-15th TSP	2.1	Refueling Outage	Deposits noted on tubes. No secondary side degradation noted.
January 1977	ONS-1B	UTS-15th TSP	2.2	Leaker Outage	Deposits noted on tubes. No secondary side degradation noted.
March 1977	ONS-1B	UTS-15th TSP	2.2	Leaker Outage	Deposits noted on tubes. No secondary side degradation noted.
May 1977	ONS-1B	UTS-15th TSP	2.3	Leaker Outage	No secondary side degradation noted.
April 1978	TMI-1A	Lower TSP and annulus	2.8	Secondary inspection in conjunction with lower secondary handhole removal for orifice plate adjustment attempt.	No abnormal wrapper conditions were noted during the LTS exam. No deposits noted on tubes. No secondary side degradation noted.
April 1978	TMI-1B	Lower TSP and annulus	2.8	Secondary inspection in conjunction with lower secondary handhole removal for orifice plate adjustment attempt.	No abnormal wrapper conditions were noted during the LTS exam. No deposits noted on tubes. No secondary side degradation noted.
April, May 1986	TMI-1A	Inspection of secondary side between 2nd and 7th TSPs, 15th TSP (uppermost span)	3.0	Inspect for tubesheet fouling.	No abnormal wrapper conditions were noted during the LTS exam. No indication of debris or damage was found at uppermost span.
September-November	ONS-1A	LTS	3.1	Refueling Outage	Deposits noted on tubes. No secondary side degradation noted.

TABLE 1
B&W-Designed OTSGs
Preliminary Secondary Side Visual Inspection / Work History
(Arranged by EFPY for all B&W-Designed Plants)

Date	OTSG	Inspection Location(s)	EFPY (approx.)	Purpose	Results
1978					
September-November 1978	ONS-1B	LTS	3.1	Refueling Outage	Deposits noted on tubes. No secondary side degradation noted.
May 1983	CR-3B	MFW and AFW Nozzles	3.1	Refueling Outage	Deposits noted on tubes and TSPs. No secondary side degradation noted.
July 1980	ANO-1A	LTS, MFW Nozzle (x-axis), 15th TSP	3.5	Leaker Outage	Deposits noted on tubes. No secondary side degradation noted.
May 1983	CR-3B	9th and 10th TSG 15th and UTSF Untubed Lane 16th Freespan	3.5	Refueling Outage	Deposits noted on tubes and TSPs. No secondary side degradation noted.
January 1987 (Outage 6R)	TMI-1A	AFW nozzles were replaced, "cursory" video inspection performed.	3.6	Repair cracked AFW nozzle collar welds	Deposits noted on tubes. No secondary side degradation noted.
January 1981	ANO-1A	14th TSP – UTS, 9th-10th TSP, 5th –6th TSP	3.8	Pre-Water Lancing/Post Water Lancing	Deposits noted on tubes and TSPs pre-water lancing. No deposits noted post water lancing. No secondary side damage or degradation was observed in the regions inspected either before or after water lancing.
January 1981	ANO-1B	AFW Nozzle z-axis MFW Nozzle x-axis	3.8	Pre Water Lancing	Deposits noted on TSPs. No secondary side degradation noted.
June to August 1988	TMI-1A	Lower Secondary Manway and Handhole	4.7	Pre-Post water slap cleaning / sludge lancing	No abnormal wrapper conditions were noted during the LTS exam. Deposits noted on tubes and TSPs pre-water slap/sludge lancing. No deposits

TABLE 1 B&W-Designed OTSGs Preliminary Secondary Side Visual Inspection / Work History (Arranged by EFPY for all B&W-Designed Plants)					
Date	**OTSG**	**Inspection Location(s)**	**EFPY (approx.)**	**Purpose**	**Results**
					noted post water slap/sludge lancing. No secondary side damage or degradation was observed in the regions inspected either before or after water lancing.
June to August 1988	TMI-1B	Lower Secondary Manway and Handhole	4.7	Pre-Post water slap cleaning / sludge lancing	No abnormal wrapper conditions were noted during the LTS exam. Deposits noted on tubes and TSPs pre-water slap/sludge lancing. No deposits noted post water slap/sludge lancing. No secondary side damage or degradation was observed in the regions inspected either before or after water lancing.
April 1985	CR-3A	3rd - 6th TSP	4.8	Refueling Outage. Pressure pulse cleaning inspections.	Deposits noted on tubes pre-pressure pulse. No deposits noted on tubes post pressure pulse. No secondary side damage or degradation was observed in the regions inspected either before or after pressure pulse cleaning.
May 1982	ONS-3A	Upper Manway x-axis	5.1	AFW Header Inspection Refueling Outage	Header distorted slightly toward w-axis and considerably more distorted toward the y-axis; distortion was away from shell toward tubes; bracket/dowel pin locations #1,2,3 and 4 were observed; some brackets were bent while others were intact. Some erosion on top of the nozzle and some wear on the nozzle were observed where AFW Nozzle entered ring header.

TABLE 1
B&W-Designed OTSGs
Preliminary Secondary Side Visual Inspection / Work History
(Arranged by EFPY for all B&W-Designed Plants)

Date	OTSG	Inspection Location(s)	EFPY (approx.)	Purpose	Results
May 1982	ONS-3B	Upper Manway x-axis	5.1	AFW Header Inspection Refueling Outage EOC-6	More distortion than in "A" SG; distortion in both W and Y Direction; brackets/dowel pins #1,2,3 and 4 similar to "A" SG. Wear or erosion apparent on aux. FW Nozzle
January 1986	CR-3A	3rd - 6th TSPs	5.2	Unplanned RCP maintenance outage.	Deposits noted on TSPs. No secondary side degradation noted.
March 1990	DB-1A&B	Internal AFW Header Supply	5.5	AFW Header Inspection	No evidence of movement or degradation of AFW header. AFW supply nozzles and thermal sleeves also inspected with the internal header and also displayed no degradation.
October 1987	CR-3A & B	S/G A: 1st & 3rd-6th TSP before cleaning, 4th TSP midway thru cleaning, 15th TSP and UTSF	5.9	Pre-sludge lancing	Deposits noted on TSPs pre-sludge lancing. No secondary side damage or degradation was observed in the regions inspected either before or after water-slap cleaning.
February 1990	TMI-1A	LTS, 3rd-6th TSP Replaced all MFW nozzles in OTSG A&B	6.0	Visually inspect Sludge on TSPs.	No secondary side degradation noted.
October 1984	ANO-1A	5th – 6th TSP, LTS	6.1	Pre /Post Water Slap	Deposits noted on tubes and TSPs prior to water slap. No deposits noted after water slap. No secondary side damage or degradation was observed in regions inspected either before or after water slap.

TABLE 1
B&W-Designed OTSGs
Preliminary Secondary Side Visual Inspection / Work History
(Arranged by EFPY for all B&W-Designed Plants)

Date	OTSG	Inspection Location(s)	EFPY (approx.)	Purpose	Results
March-September 1985	ONS-2B	LTS, 9th TSP	7.1	Pressure Pulse Refueling Outage	No secondary side degradation noted.
March-September 1985	ONS-2A	4th-5th TSP ,10th TSP	7.1	Pressure Pulse Refueling Outage	Deposits noted on tubes. No secondary side damage or degradation was observed in regions inspected either before or after pressure pulse.
April 1990 (Outage 7)	CR-3A & B	3rd-4th TSP	7.3	Pre-post water slap inspections. Fouling occurred at these evaluations and only these two tsp. Looked at to reduce cost/time	No secondary side damage or degradation was observed in regions inspected either before or after water-slap cleaning.
October 1984	ONS-1A	LTS	7.3	Refueling Outage	No secondary side degradation noted.
October 1984	ONS-1B	LTS, 9th-10th TSP	7.3	Refueling Outage	Deposits noted on tubes and TSPs. No secondary side degradation noted No secondary side degradation noted.
November 1991 (Outage 9R)	TMI-1A	Lower Secondary Manway and #10 handholes removed.	8.2	Sludge Lancing following Chemical Cleaning	No debris noted on the tubesheet. No abnormal wrapper conditions were noted during the LTS exam. No secondary side degradation noted.
November 1991	TMI-1B	Lower Secondary Manway and #10 handholes removed.	8.2	Sludge Lancing following Chemical Cleaning	No debris noted on the tubesheet. No abnormal wrapper conditions were noted during the LTS exam. No secondary side degradation noted.
May 1992	CR-3A & B	1st TSP in both 3rd and 4th TSP in SG-A before and after water-slap cleaning	8.7	Pre-post water slap inspections	No secondary side damage or degradation was observed in regions inspected either before or after water-slap cleaning.

TABLE 1
B&W-Designed OTSGs
Preliminary Secondary Side Visual Inspection / Work History
(Arranged by EFPY for all B&W-Designed Plants)

Date	OTSG	Inspection Location(s)	EFPY (approx.)	Purpose	Results
February 1988	ONS-2A	LTS, 3rd TSP –6th TSP	9.4	Pre-/Post -Chemical Cleaning Refueling Outage	Deposits noted on tubes and TSPs prior to chemical cleaning. No deposits noted post chemical cleaning. No secondary side degradation noted.
February 1988	ONS-2B	LTS, 3rd –6th TSP	9.4	Pre-/Post-Chemical Cleaning Refueling Outage	Deposits noted on tubes and TSPs prior to chemical cleaning. No deposits noted post chemical cleaning. No secondary side degradation noted.
September 1987	ONS-1A	LTS, 4th-7th TSP	9.5	Pre-/Post-Chemical Cleaning Refueling Outage	Deposits noted on tubes and TSPs prior to chemical cleaning. No deposits noted post chemical cleaning. No secondary side degradation noted.
September 1987	ONS-1B	LTS, 4th – 7th TSP, 9th TSP	9.5	Pre-/Post-Chemical Cleaning Refueling Outage	Deposits noted on tubes and TSPs prior to chemical cleaning. No deposits noted post chemical cleaning. No secondary side degradation noted.
October 1990	ANO-1A	5th –6th TSP	9.6	Pre-/Post- Chemical Cleaning	Deposits noted on tubes and TSPs prior to chemical cleaning. No deposits noted post chemical cleaning. No secondary side degradation noted.
May 1994	CR-3B	Up to the 9th TSP	10.3	Inspection of supports through pulled tube hole.	Deposits noted on tubes and TSPs. No secondary side degradation noted.
April 1996	DB-1A	LTS-1st TSP, 4th-5th TSP	10.6	Refueling Outage	Deposits noted on tubes and TSPs. No secondary side degradation noted.
April 1996	DB-1B	LTS-1st TSP, 4th-5th TSP	10.6	Refueling Outage	Deposits noted on tubes and TSPs. No secondary side degradation noted.

TABLE 1
B&W-Designed OTSGs
Preliminary Secondary Side Visual Inspection / Work History
(Arranged by EFPY for all B&W-Designed Plants)

Date	OTSG	Inspection Location(s)	EFPY (approx.)	Purpose	Results
May 1990	ONS-1B	$4^{th} - 6^{th}$ TSP	11.8	Refueling Outage	Deposits noted on tubes and TSPs. No secondary side degradation noted.
April 1996	CR-3A & B	Inspection of downcomer annulus in both SGs performed by remote camera also	12.0	Pre-sludge Lancing	Deposits noted on tubes and TSPs. No secondary side degradation noted.
October 1997	TMI-1A	Tube bundle at tube pull location	13.6	Visually inspect the tube support plates (TSPs) and adjacent tubes at the tube pull location.	Deposits noted on tubes and TSPs. No secondary side degradation noted.
October 1997	TMI-1B	Tube bundle at tube pull location	13.6	The purpose of the visual inspection was to visually inspect the tube support plates (TSPs) and adjacent tubes at the tube pull location.	Deposits noted on tubes and TSPs. No secondary side degradation noted.
December 1992	ONS-3A&B	Internal AFW Header	13.9	Internal AFW Header Inspection	Deposits noted on tubes and TSPs. No secondary side degradation noted.
January-October 1994	ONS-3B	LTS	14.2	Post-Water Slap Refueling Outage	No deposits noted on tubes and TSPs. No secondary side degradation noted.
May 1994	ONS-1A	TSP 1 – 7 through pulled tube location	15.2	Refueling Outage EOC-15	Deposits noted on tubes and TSPs. No secondary side degradation noted.
June 1995	ONS-3A	LTS	15.4	Refueling Outage EOC-15, Pre-/Post-Sludge Lance Inspection	Deposits noted on LTS prior to chemical cleaning. No deposits noted post chemical cleaning. No secondary side degradation noted.
June 1995	ONS-3B	LTS	15.4	Refueling Outage EOC-15, Pre-/Post-Sludge Lance Inspection	Deposits noted on LTS prior to chemical cleaning. No deposits noted post chemical cleaning. No secondary side degradation noted.
April 1996	ONS-2A	TSP 1 – 8 through pulled	16.3	Refueling Outage EOC-15	Deposits noted on tubes and TSPs. No secondary

TABLE 1 B&W-Designed OTSGs Preliminary Secondary Side Visual Inspection / Work History (Arranged by EFPY for all B&W-Designed Plants)					
Date	**OTSG**	**Inspection Location(s)**	**EFPY (approx.)**	**Purpose**	**Results**
		tube location 14^{th}-15^{th} TSP			side degradation noted.
November 1996	ONS-3A	TSP 1 – 2 through pulled tube 100-49	16.5	Refueling Outage EOC-16	Deposits noted on TSPs. No secondary side degradation noted.
November 1996	ONS-3A	15^{th}-16^{th} TSP	16.5	Refueling Outage EOC-16	Deposits noted on tubes. No secondary side degradation noted.
October 1997	ONS-1B	MFW Nozzle #1,#32 AFW Nozzle #4	17.1	Upper Wrapper Weld Inspection	The upper wrapper weld was inspected as part of the degradation issue of SG internals. No degradation was observed. There were no signs of the wrapper shifting or of components touching any internal component. No TSP edge wear was observed.

Attachment 3

Duke Energy Corporation Response to Generic Letter 97-06 for McGuire Nuclear Station Units 1 and 2

McGuire Nuclear Station Units 1 and 2 have Babcock and Wilcox International model CFR-80 steam generators. These steam generators were installed in March and December 1997, respectively. The design, and most importantly the manufacturing philosophy, are different than those used for the manufacture of steam generators built in the early 1970's.

B&W International Replacement Recirculating Steam Generators are in operation, installation or manufacturing as follows:

Utility	Plant	In-Service	First Outage
Northeast Utilities	Millstone 2	01/93	10/94
Rochester G&E	Ginna	06/96	09/97
Duke Power	Catawba 1 McGuire 1 McGuire 2	10/96 05/97 12/97	11/97
Florida P&L	St. Lucie 1	01/98	
Commonwealth Edison	Byron 1 Braidwood 1	02/98 12/98 est.	
AEP	D. C. Cook 1	03/00 est.	

RESPONSE TO REQUIRED INFORMATION:

GL 97-06 Required Information, Response Item (1):

(1) Discussion of any program in place to detect degradation of steam generator internals and a description of the inspection plans, including the inspection scope, frequency, methods, and equipment.

Attachment 3

Response to Item (1) for McGuire Units 1 and 2:

As stated above, these are new steam generators recently installed at McGuire. There is no systematic program in place to inspect the steam generator internals.

GL 97-06 Required Information, Response Item (1)(a):

(a) Whether inspection records at the facility have been reviewed for indications of tube support plate signals anomalies from eddy-current testing of the steam generator tubes that may be indicative of support damage or ligament cracking. If the addressee has performed such a review, include a discussion of the findings.

Response to Item (1)(a) for McGuire Units 1 and 2:

At McGuire, the eddy current inspections have been reviewed for the presence of tube support structures. No anomalies were noted.

GL 97-06 Required Information, Response Item (1)(b):

(b) Whether visual or video camera inspections on the secondary side of the steam generators have been performed at the facility to gain information on the condition of steam generator internals (e.g., support plates, tube bundle wrappers, or other components). If the addressee has performed such inspections, include a discussion of the findings.

Response to Item (1)(b) for McGuire Units 1 and 2:

These are new steam generators. Inspections have been an integral part of the manufacture and installation. Quality control inspections are performed to ensure compliance of the fabricated components to design requirements, as defined by drawings and shop specifications. Ordered material is also similarly confirmed to comply with all applicable requirements. These confirmations are performed by both manufacturer and Duke representatives.

The generic letter cited failures of the tube support structures associated with the manufacturing and

installation process. The upper tube support lattice and wrapper are heavily loaded in handling (includes rotation) and shipping. Distress in the upper lattice support would be most likely to occur at the ends of the bars where they enter the peripheral ring of the support.

After completion of tubing and insertion of the steam drum internals, the steam drum to main shell closure weld (at the top of the transition cone section) is completed. A local PWHT of the steam drum to transition cone weld is then performed. Care is taken to isolate any PWHT or related effects from the internals by insulating and evacuating the inside of the steam generator and by adherence to temperature and temperature differential limits during the PWHT process. Vessel thermal treatment is thereby removed as a possible concern regarding integrity of the tubing, tube supports, or shroud structures.

The U-bend of the tubes was always supported during the manufacturing process to prevent bending of the tube and overloading of the lattice grid and wrapper. This support was then maintained by the installation of temporary shipping restraints. These shipping restraints are removed after the steam generators are placed vertical. This peripheral region is readily visible after assembly of the steam generator. Visual inspections of this region are performed at a number of points during manufacturing and installation. No observation of distress or degradation has been observed.

Additional inspections performed after installation of the steam generators in the vertical position at McGuire included visual inspection of the tubesheet annulus region for foreign objects. No significant objects were found.

At McGuire Unit 2, in-situ preservice eddy current testing provided information regarding tube proximity after uprighting. Consequently, this testing included any effects of manufacturing, handling and transportation. The steam generator tubes were observed to be in correct proximity.

Attachment 3

GL 97-06 Required Information, Response Item (1)(c):

(c) Whether degradation of steam generator internals has been detected at the facility, and how the degradation was assessed and dispositioned.

Response to Item (1)(c) for McGuire Units 1 and 2:

During the manufacture of some of the other utilities replacement steam generators, the positioning of the U-bend support components could have resulted in contact between peripheral tubes. The U-bend support structure, which is free to move with the U-bend during operating transients, is supported at the peripheral tubes by "L" or "J" shaped elements called J-tabs. It was determined that the positioning of some of the J-tabs during manufacture may cause contact between certain pairs of vertically adjacent peripheral tube U-bends. The potential for and effect of this condition has been assessed by the original equipment manufacturer. The assessment has confirmed that while some fretting may occur at contact locations, it will be less than that predicted at the tube support locations, and will not be sufficient to limit operation of the tubing. In-situ inspections of the steam generators have indicated that tube proximity (less than desired clearance or possible contact) is indicated for a relatively small number of tubes on a number of the replacement steam generators.

GL 97-06 Required Information, Response Item (2):

(2) If the addressee currently has no program in place to detect degradation of steam generator internals, include a discussion and justification of the plans and schedule for establishing such a program, or why no program is needed.

Response to Item (2) for McGuire Units 1 and 2:

NRC Generic Letter GL 97-06 identifies six degradation mechanisms which have been observed on various European and domestic PWR steam generators. The potential for these mechanisms to occur in B&W replacement steam generators (provided as replacements for the original equipment) and any resulting recommended confirmatory inspections are assessed as follows.

Attachment 3

The design configuration and materials of internal components of B&W Canada Replacement Recirculating Steam Generators for PWR plants are different in most respects than the cited units. The tube supports are made of a 410S stainless steel lattice bar configuration, as compared to carbon steel drilled-plates (or eggcrate supports) for the units cited as having degradation. U-bend supports are of a 410S material flat bar construction. The bundle wrapper is supported to the main shell by robust lugs with full penetration welds at the lower end and by radial pins at various tube support elevations along the wrapper height. These, along with the tube supports, are arranged (and analyzed) to accommodate thermal motions during operation as well as accident related loads. No manufacturing thermal loads apply since all relevant (lower vessel) post weld heat treatment is performed before installation of the internals. No full vessel post weld heat treatment is performed.

In total, 30 replacement steam generator units are in service or under construction for nine reactor units, operated by six different utilities. These replace original equipment manufacture's steam generators of System 67 and Model D, 44 and 51 designs. Of this total, 22 are in service, and 8 steam generators at 3 plants have completed inspections after the first fuel cycle operation.

Degradation Assessment

The effect/relevance of the individual mechanisms are addressed as follows:

1. Support Plate Wastage Due to Chemical Cleaning - is not currently relevant as none of these units have been chemically cleaned. In addition, the materials and designs have generally been pre-qualified for multiple application of a chemical cleaning process at some time in the future.

2. Broken Tube Support Ligaments - is not directly relevant because tube supports are lattice bar type rather than drilled plates. Damage to tube supports during manufacturing thermal cycles is avoided by the installation of the internals after heat treatment of the lower vessel. Consequently, the tube bundle, tube supports, wrapper and

related structures are not exposed to thermal effects. The shell closure weld, which is performed after tubing, is located at the conical shell and is carefully isolated from the tube bundle, tube supports, and wrapper. The closure weld is also carefully monitored/controlled during post weld heat treatment activities.

During operating transients such as heatup, the tubing, tube supports, wrapper, and particularly the shell may respond thermally at different rates. In such a case, the shell temperature lag will resist free radial and axial expansions of the wrapper, tube supports, etc. Such conditions are accommodated by local flexibility within the wrapper design, which provides for the necessary differential expansion motions.

As noted in the response to Question (1)(b), the installation of manufacturing and shipping restraints reduced the potential for damage to the upper most lattice grid. This has been verified by inspections.

3. Support Plate Wastage in Operation - due to corrosion conditions is addressed by material selection of the lattice bar and U-bend support bar material. The 410S stainless steel material is conditioned to provide the necessary corrosion resistance as well as structural strength.

4. Wrapper Drop - due to failure of wrapper support lugs during vessel manufacturing, is avoided by installing the wrapper after vessel thermal treatment. Failure during operation is addressed by providing robust shell lugs with full penetration welds to support the lower edge of the wrapper, and by accommodating radial/vertical wrapper versus shell growth during operation. This is accomplished by providing the necessary wrapper flexibility.

5. Wrapper Cracking - due to possible wrapper vibratory motion, is avoided by effectively providing anti-vibration support at numerous points, including each of the fixed lower shroud lugs, and by the many levels of wrapper (to shell) lateral support pins. In addition, each of the lattice grid support ring-to-wrapper wedge points provides additional restraint for this type of condition.

6. Degradation of Eggcrate Supports - due to flow/corrosion effects, is addressed by the selection of 410S stainless steel for the lattice bars. 410S is a material with corrosion resistance and strength suitable for the operating conditions.

There are no safety concerns with the continued operation of the McGuire steam generators associated with the current secondary side degradation mechanisms quoted in GL 97-06. Therefore, no immediate near term inspections are required. No new potential degradation mechanisms have been proposed.

These are relatively new models of steam generators, with the oldest being Millstone 2. Three visual inspections have been performed after one period of operation on each of: Millstone 2, Ginna, and Catawba 1. No adverse trends have been noted during these inspections.

Consistent with the requirements of NEI 97-06 and Duke's commitment to follow the NEI initiative, a program will be established to monitor the secondary-side steam generator components. This program will be applied to components whose failure could prevent the steam generators from fulfilling their intended function .

Attachment 4

Duke Energy Corporation Response to Generic Letter 97-06 for Catawba Nuclear Station Unit 1

Catawba Nuclear Station Unit 1 has Babcock and Wilcox International model CFR-80 steam generators. These steam generators were installed in September 1996. The design, and most importantly the manufacturing philosophy, are different than those used for the manufacture of steam generators built in the early 1970's.

B&W International Replacement Recirculating Steam Generators are in operation, installation or manufacturing as follows:

Utility	Plant	In-Service	First Outage
Northeast Utilities	Millstone 2	01/93	10/94
Rochester G&E	Ginna	06/96	09/97
Duke Power	Catawba 1 McGuire 1 McGuire 2	10/96 05/97 12/97	11/97
Florida P&L	St. Lucie 1	01/98	
Commonwealth Edison	Byron 1 Braidwood 1	02/98 12/98 est.	
AEP	D. C. Cook 1	03/00 est.	

RESPONSE TO REQUIRED INFORMATION:

GL 97-06 Required Information, Response Item (1):

(1) *Discussion of any program in place to detect degradation of steam generator internals and a description of the inspection plans, including the inspection scope, frequency, methods, and equipment.*

Response to Item (1) for Catawba Unit 1:

As stated above, these are new steam generators recently installed at Catawba Unit 1. There is no formal program in place to inspect the steam generator internals.

Attachment 4

GL 97-01 Required Information, Response Item (1)(a):

(a) Whether inspection records at the facility have been reviewed for indications of tube support plate signals anomalies from eddy-current testing of the steam generator tubes that may be indicative of support damage or ligament cracking. If the addressee has performed such a review, include a discussion of the findings.

Response to Item (1)(a) for Catawba Unit 1:

At Catawba Unit 1 the eddy current inspections have been reviewed for the presence of tube support structures. No anomalies were noted.

GL 97-06 Required Information, Response Item (1)(b):

(b) Whether visual or video camera inspections on the secondary side of the steam generators have been performed at the facility to gain information on the condition of steam generator internals (e.g., support plates, tube bundle wrappers, or other components). If the addressee has performed such inspections, include a discussion of the findings.

Response to Item (1)(b) for Catawba unit 1:

These are new steam generators. Inspections have been an integral part of the manufacture and installation. Quality control inspections are performed to ensure compliance of the fabricated components to design requirements, as defined by drawings and shop specifications. Ordered material is also similarly confirmed to comply with all applicable requirements. These confirmations are performed by both the manufacturer and Duke representatives.

The generic letter cited failures of the tube support structures associated with the manufacturing and installation processes. The upper tube support lattice and wrapper are heavily loaded in handling (includes rotation) and shipping. Distress in the upper lattice support would be most likely to occur at the ends of the bars where they enter the peripheral ring of the support.

Attachment 4

After completion of tubing and insertion of the steam drum internals, the steam drum to main shell closure weld (at the top of the transition cone section) is completed. A local PWHT of the steam drum to transition cone weld is then performed. Care is taken to isolate any PWHT or related effects from the internals by insulating and evacuating the inside of the steam generator and by adherence to temperature and temperature differential limits during the PWHT process. Vessel thermal treatment is thereby removed as a possible concern regarding integrity of the tubing, tube supports, or shroud structures.

The U-bend of the tubes was always supported during the manufacturing process to prevent bending of the tube and overloading of the lattice grid and wrapper. This support was then maintained by the installation of temporary shipping restraints. These shipping restraints are removed after the steam generators are placed vertical. This peripheral region is readily visible after assembly of the steam generator. Visual inspections of this region are performed at a number of points during manufacturing and installation. No observation of distress or degradation has been observed.

Additional inspections performed after installation of the steam generators in the vertical position at Catawba included visual inspection of the tubesheet annulus region for foreign objects. No significant objects were found.

As part of the Catawba Unit 1 steam generator program, in December 1997, during the first refueling outage after replacement, the "A" steam generator upper steam drum was entered and visually inspected. The following areas were inspected in part: primary and secondary decks, supports, hatches, primary and secondary moisture separators, feedring and supports, feedwater header "J" tubes, top of the tube bundle, downcomer components, seismic pins, wrapper lug, and a section of the top of the tube sheet. No erosion or corrosion was observed. Separator drains were open. No meaningful scale buildup on the primary and secondary moisture separators was noted. Nothing was adrift. Welds appeared normal. No debris was found on the primary or intermediate decks. The results of a sample taken of a

light dusting of corrosion products on the primary deck near the assess hatch indicated the material consisted principally of magnetite.

There was no steam generator wrapper to shell misalignment nor was any wrapper drop noted in the Catawba Unit 1 "A" steam generator.

GL 97-06 Required Information, Response Item (1)(c):

(c) Whether degradation of steam generator internals has been detected at the facility, and how the degradation was assessed and dispositioned.

Response to Item (1)(c) for Catawba Unit 1:

During the manufacture of some of the other utilities replacement steam generators, the positioning of the U-bend support components could have resulted in contact between peripheral tubes. The U-bend support structure, which is free to move with the U-bend during operating transients, is supported at the peripheral tubes by "L" or "J" shaped elements called J-tabs. It was determined that the positioning of some of the J-tabs during manufacture may cause contact between certain pairs of vertically adjacent peripheral tube U-bends. The potential for and effect of this condition has been assessed by the original equipment manufacturer. The assessment has confirmed that while some fretting may occur at contact locations, it will be less than that predicted at the tube support locations and will not be sufficient to limit operation of the tubing. In-situ inspections of the steam generators have indicated that tube proximity (less than desired clearance or possible contact) is indicated for a relatively small number of tubes on a number of the replacement steam generators.

During the December 1997 inspection, Catawba Unit 1 did observe some periphery tubes in proximity by eddy current inspection. However, there was no degradation associated with these tubes.

GL 97-06 Required Information, Response Item (2):

(2) If the addressee currently has no program in place to detect degradation of steam generator internals, include

a discussion and justification of the plans and schedule for establishing such a program, or why no program is needed.

Response to Item (2) for Catawba Unit 1:

NRC Generic Letter GL 97-06 identifies six degradation mechanisms which have been observed on various European and domestic PWR steam generators. The potential for these mechanisms to occur in B&W replacement steam generators (provided as replacements for the original equipment) and any resulting recommended confirmatory inspections are assessed as follows.

The design configuration and materials of internal components of B&W Canada Replacement Recirculating Steam Generators for PWR plants are different in most respects than the cited units. The tube supports are made of a 410S stainless steel lattice bar configuration as compared to drilled-plates (or eggcrate supports) of carbon steel for the units cited with degradation. U-bend supports are made of a 410S material flat bar construction. The bundle wrapper is supported to the main shell by robust lugs with full penetration welds at the lower end and by radial pins at various tube support elevations along the wrapper height. These, along with the tube supports, are arranged (and analyzed) to accommodate thermal motions during operation as well as accident related loads. No manufacturing thermal loads apply since all relevant (lower vessel) post weld heat treatment is performed before installation of the internals. No full vessel post weld heat treatment is performed.

In total, 30 replacement steam generator units are in service or under construction for nine reactor units, operated by six different utilities. These replace original equipment manufacture's steam generators of System 67 and Model D, 44 and 51 designs. Of this total, 22 are in service, and 8 steam generators at 3 plants have completed inspections after the first fuel cycle operation.

Degradation Assessment

The effect/relevance of the individual mechanisms are addressed as follows:

Attachment 4

1. Support Plate Wastage Due to Chemical Cleaning - is not currently relevant as none of these units have been chemically cleaned. In addition, the materials and designs have generally been pre-qualified for multiple application of a chemical cleaning process at some time in the future.

2. Broken Tube Support Ligaments - is not directly relevant because tube supports are lattice bar type rather than drilled plates. Damage to tube supports during manufacturing thermal cycles is avoided by installation of the internals after heat treatment of the lower vessel. Consequently, the tube bundle, tube supports, wrapper, and related structures are not exposed to thermal effects. The shell closure weld, which is performed after tubing, is located at the conical shell and is carefully isolated from the tube bundle, tube supports, and wrapper. The closure weld is also carefully monitored/controlled during post weld heat treatment activities.

   During operating transients such as heatup, the tubing, tube supports, wrapper, and particularly the shell may respond thermally at different rates. In such a case, the shell temperature lag will resist free radial and axial expansions of the wrapper, tube supports, etc. Such conditions are accommodated by local flexibility within the wrapper design, which provides for the necessary differential expansion motions.

   As noted in the response to Question (1)(b), the installation of manufacturing and shipping restraints reduced the potential for damage to the upper most lattice grid. This has been verified by inspections.

3. Support Plate Wastage in Operation - due to corrosion conditions, is addressed by material selection of the lattice bar and U-bend support bar material. The 410S stainless steel material is conditioned to provide the necessary corrosion resistance as well as structural strength.

4. Wrapper Drop - due to failure of wrapper support lugs during vessel manufacturing, is avoided by installing the wrapper after vessel thermal

treatment. Failure during operation is addressed by providing robust shell lugs with full penetration welds to support the lower edge of the wrapper, and by accommodating radial/vertical wrapper versus shell growth during operation. This is accomplished by providing the necessary wrapper flexibility.

5. Wrapper Cracking - due to possible wrapper vibratory motion, is avoided by effectively providing anti-vibration support at numerous points, including each of the fixed lower shroud lugs, and by the many levels of wrapper (to shell) lateral support pins. In addition, each of the lattice grid support ring-to-wrapper wedge points provides additional restraint for this type of condition.

6. Degradation of Eggcrate Supports - due to flow/corrosion effects, is addressed by selection of 410S stainless steel for the lattice bars. 410S is a material with corrosion resistance and strength suitable for the operating conditions.

There are no safety concerns with the continued operation of the Catawba Unit 1 steam generators associated with the current secondary side degradation mechanisms quoted in GL 97-06. Therefore, no immediate near term inspections are required. No new potential degradation mechanisms have been proposed.

These are relatively new models of steam generators, with the oldest being Millstone 2. Three visual inspections have been performed after one period of operation on each of: Millstone 2, Ginna, and Catawba 1. No adverse trends have been noted during these inspections.

Consistent with the requirements of NEI 97-06 and Duke's commitment to follow the NEI initiative, a program will be established to monitor the secondary-side steam generator components. This program will be applied to components whose failure could prevent the steam generators from fulfilling their intended function.

Attachment 5

Duke Energy Corporation Response to Generic Letter 97-06 for Catawba Nuclear Station Unit 2

Prior to issuance of the Generic Letter, the Westinghouse Owners Group (WOG), the Electric Power Research Institute (EPRI) and the Nuclear Energy Institute (NEI) developed an action plan to assess the susceptibility to secondary-side degradation. Included in the action plan is a requirement to understand the causal factors involved in the degradation experienced in the French Units. Due to the similarity of design between the EdF units and Westinghouse series 51 steam generators, the WOG evaluations of the series 51 steam generators were performed first. A similar detailed evaluation is planned for the remaining types of steam generators (Model 44F, F, D3, D5, and E1/E2). Catawba Unit 2 has Westinghouse Model D5 steam generators installed. The WOG detailed evaluation has not been completed for the model D5 steam generators. However, preliminary Model D5 results indicate a low susceptibility to various identified internals degradation modes, with the exception of the waterbox rib structure erosion/corrosion.

RESPONSE TO REQUIRED INFORMATION:

GL 97-06 Required Information, Response Item (1):

(1) Discussion of any program in place to detect degradation of steam generator internals and a description of the inspection plans, including the inspection scope, frequency, methods, and equipment.

Response to Item 1 for Catawba Unit 2:

Catawba Unit 2 has no formal program to inspect/monitor steam generator internals degradation. However, as a result of other steam generator (SG) activities, such as sludge lancing and foreign objects, secondary side inspections have been conducted. Visual inspections have been performed on the tubesheet, at the 18th tube support plate, in the T-slot, steam drum, and the upper bundle. No adverse trends have been noted.

As discussed in WCAP -15002, Revision 1, surveys were sent to all WOG utilities requesting the results of all steam generator secondary side inspections and relevant tube

inspections for tube support plate conditions. Completed surveys were received from 37 of 49 plants. For the Model D, E, 44F, and F steam generators, responses were received for 12 plants. Of these, 11 responded as having inspected or reviewed inspection data for tube support plate (TSP) ligament indications, and 8 as having performed steam generator secondary side entries that gave confidence of not having wrapper drop. TSP ligament indications were not found in either steam generators with carbon steel support plates, or in steam generators with stainless steel support plates.

The detected modes of degradation included many cases of flow-assisted corrosion, or erosion-corrosion; and of premature cracking that results from either surface fatigue, or from corrosion cracking that is associated with surface conditions such as pitting or geometric concentrations. For the most part, however, the surveys do not report detection of several modes of degradation experienced in the EdF units. There is no evidence of post chemical cleaning inspections discovering any significant material losses. There is no evidence of any wrapper having dropped. There is no evidence of TSP ligament cracking or thinning that is progressive and continuing. TSP ligament or missing pieces of ligaments have been observed, but only in units with carbon steel support plates with drilled round tube holes and flow holes. These conditions are generally traceable to initial inspections and are not progressing based on sequential inspections data. Many of the conditions are probably related to original TSP drilling alignment. There are cases of indications in TSPs that have been linked to patch plate welds.

Plants with significant hour glassing of the tube support plates (as a result of the denting process) have exhibited ligament cracking throughout the thickness of the support plate between the flow holes in the plate, or the flow holes in the tube lane. If the denting remains uncontrolled, as subsequent support plate corrosion occurs, the potential exists for fragments of the support plate material to become completely free of the main TSP structure. However, these plate segments generally remain locked in place because of the in-plane forces that give rise to denting, as well as the deformation that contains the individual piece. Operating plants with active denting are under periodic monitoring by the utility and have long standing criteria reviewed by the NRC. In addition, the reported EdF experiences are not related to plate degradation that has

progressed to the tube denting stage. These plants are therefore not included in this response to GL 97-06.

During routine eddy current inspection in one Model D4 steam generator at one plant, tube wear indications believed to be caused by a foreign object were detected on several row 49 tubes just above the B plate, cold leg side. It was decided to retrieve the object(s); however, in order to gain access to this region, the main feedwater pipe was required to be separated at the feedwater nozzle entrance. Upon examining the preheater water box area, two cylindrical objects were found and erosion/corrosion was observed on the vertical support ribs. Tese are welded to the outside of the steam generator impingement plate in the water box area.

In the Model D4 steam generator, the impingement plate is a ¾" thick carbon steel plate which forms one vertical surface of the preheat region. As the feedwater flow enters into the steam generator through the main nozzle, the flow directly impacts an 18" diameter Alloy 600 target plate, which is welded to the outside surface of a carbon steel impingement plate. The impingement plate and wrapper are welded at a Y forging at the corners, closing off the water box at the vertical edges.

The main feedwater is directed downward as it enters the water box area and is turned by the B baffle plate to enter the preheater. As the flow radiates from the impingement plate, the carbon steel support ribs are directly in the path of the flow. Four vertically oriented support ribs are used. All four ribs are in line with the steam generator vertical axis. The side ribs are perforated with two rows of 1 inch diameter holes on a 1.5" pitch, while the top and bottom ribs have three rows of holes. The top and bottom ribs are taller than the side ribs, since the distance from the impingement plate to the wrapper is the largest at the nozzle centerline. A perforated cap plate is located at the top of the impingement plate perpendicular to the vertical support ribs, and this closes the water box at the top. Approximately 12" of length of the side ribs were observed to be eroded away, resulting in loss of the perforated structure with coalescence of the flow holes, centered about or slightly below the main nozzle centerline. A preferential attach of the bottom row of perforated holes appears to have occurred towards the B plate as opposed to towards the cap plate. The circular shape of the original 1 inch holes in the support ribs are enlarged, resulting in coalescence of the holes in the eroded missing length. No

erosion/corrosion of the wrapper, impingement plate, target plate, or impingement plate to target plate weld was detected by visual inspection.

Based on the information gathered to date, it can be qualitatively concluded that any separated rib pieces would be small, and that the erosion/corrosion pattern occurring in the ribs will be a gradual enlargement of the 1" holes with eventual coalescence of the flow holes. For the Model D4, D5 and E steam generators, the outer row tubes have been expanded to contact (or to near contact) at the B and D plates on the cold leg side. Tube wear rates at the top of the B plate for an assumed object would not result in tube wear to a depth of at least 40% through-wall in less than several operational cycles. The limiting location with respect to tube wear is the grouping of tubes located at the back of the T-slot. These tubes experience substantial flow velocities and are not expanded. Thus, they exhibit larger amplitudes of vibration than the outer row tubes that were expanded prior to operation. Row 49 tubes (Row 48 in Model E steam generators), back of T-slot tubes, and vibration susceptible peripheral tubes will be eddy current inspected in the preheat region. This practice will be followed to determine if wear is occurring/accelerating at the preheater plates and to determine if wear due to foreign objects/loose parts interaction is occurring. Actions will be taken as appropriate to address any tube wear considerations.

Catawba Unit 2 has performed an eddy current inspection of these tubes in the periphery and the T-slot region. No adverse trends were noted.

The secondary side internal degradation types found in Westinghouse steam generators are identified in the following table:

Attachment 5

Secondary Side Internal Degradation Types In Westinghouse Design SGs

SG Category: / Degradation Type	Feed Ring Carbon Steel TSPs	Preheat Carbon Steel TSPs	Feed Ring Stainless Steel TSPs	Preheat Stainless Steel TSPs (D5)
Erosion-Corrosion:				
Moisture Separator	X	S	X	S
Water Box	NA	X(4)	NA	S
TSP Flow Hole /Ligaments	S	S	NA	NA
Feed Ring /J-Tubes	X	NA	X	NA
Cracking:				
TSP Ligaments(1), (2)	X	S	L	L
Wrapper Near Supports(2)	L	L	L	L
Transition Cone Girth Weld	X	L	X(3)	L
Other:				
Wrapper Drop(2)	L	L	L	L

X = Observed in Some Steam Generators.
S = Susceptible
L = Low Susceptibility
NA = Not Applicable

(1) Various indications of possible TSP degradation may be artifacts of manufacturing anomalies related to patch plate plug welds and drilling alignment.
(2) Various Westinghouse design features are beneficial relative to the modifications incorporated in some SGs of foreign manufacturers.
(3) In a SG replacement with the original upper shell not replaced.
(4) This mechanism does not apply to the Model D3 because of the Alloy 600, inlet manifold design used.

Attachment 5

Catawba Unit 2 is a preheat steam generator with quatrefoil stainless steel TSP's.

GL 97-06 Required Information, Response Item (1)(a):

(a) Whether inspection records at the facility have been reviewed for indications of tube support plate signals anomalies from eddy-current testing of the steam generator tubes that may be indicative of support damage or ligament cracking. If the addressee has performed such a review, include a discussion of the findings.

Response to Item (1)(a) for Catawba Unit2:

At Catawba Unit 2 the eddy current inspections have been reviewed for the presence of tube support structures. No anomalies were noted.

GL 97-06 Required Information, Response Item (1)(b):

(b) Whether visual or video camera inspections on the secondary side of the steam generators have been performed at the facility to gain information on the condition of steam generator internals (e.g., support plants tube bundle wrappers, or other components). If the addressee has performed such inspections, include a discussion of the findings.

Response to Item (1)(b) for Catawba Unit 2:

As a result of other steam generator activities, such as sludge lancing and foreign objects, secondary side inspections have been conducted. Visual inspections have been performed on the tubesheet, at the 18th tube support plate, in the T-slot, steam drum, and the upper bundle. No adverse trends have been noted.

GL 97-06 Required Information, Response Item (1)(c):

(c) Whether degradation of steam generator internals has been detected at the facility, and how the degradation was assessed and dispositioned.

Attachment 5

Response to Item (1)(c) for Catawba Unit 2:

No degradation of internals has been noted at Catawba Unit 2

GL 97-06 Required Information, Response Item (2):

(2) If the addressee currently has no program in place to detect degradation of steam generator internals, include a discussion and justification of the plans and schedule for establishing such a program, or why no program is needed.

Response to Item 2 for Catawba Unit 2:

WCAP-15002, Revision 1, documents visual inspections of the plants. It is concluded that the number of plants that have been inspected and the inspection results demonstrate that the causal factors identified by EdF do not jeopardize the continued operability of Westinghouse Model D5 steam generators.

A detailed evaluation by the WOG has not been completed for the model D5 steam generators installed at Catawba Unit 2. The more detailed evaluation should be completed by the end of May 1998.

Consistent with the requirements of NEI 97-06 and Duke's commitment to follow the NEI initiative, a program will be established to monitor the secondary-side steam generator components. This program will be applied to components whose failure could prevent the steam generators from fulfilling their intended function.