UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

April 1, 1992

Docket No. 50-364

Mr. W. G. Hairston, III
Senior Vice President
Southern Nuclear Operating
Company, Inc.
Post Office Box 1295
Birmingham, Alabama 35201-1295

Dear Mr. Hairston:

SUBJECT: ISSUANCE OF AMENDMENT NO. 87 TO FACILITY OPERATING LICENSE NO. NPF-8 REGARDING STEAM GENERATOR TUBE INTERIM PLUGGING CRITERIA - JOSEPH M. FARLEY NUCLEAR PLANT, UNIT 2 (TAC NO. M82810)

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 87 to Facility Operating License NPF-8 for the Joseph M. Farley Nuclear Plant, Unit 2. The amendment changes the Technical Specifications in response to your submittal dated February 20, 1992, as supplemented on March 27, 1992.

The amendment changes Technical Specifications 4.4.6.4 and 3.4.7.2, and Bases 3/4.4.6, to allow the implementation of interim steam generator tube plugging criteria for the tube support plate elevations. The amendment also reduces the allowed primary-to-secondary operational leakage from any one steam generator from 500 gallons per day to 150 gallons per day. The total allowed primary-to-secondary operational leakage through all steam generators is reduced from one gallon per minute (1440 gallons per day) to 450 gallons per day. This amendment is only applicable for the ninth operating cycle.

CP-1

DFOI
1/1

150032

A copy of our related Safety Evaluation is also enclosed. A Notice of Issuance will be included in the Commission's bi-weekly Federal Register notice.

Sincerely,

Orignal signed by:

Stephen T. Hoffman, Project Manager
Project Directorate II-1
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Amendment No. 87 to NPF-8
2. Safety Evaluation

cc w/enclosures:
See next page

Distribution:
See attached page

OFC	PDII-1/LA	PDII-1/PM	OGC	PDII-1/D
NAME	PAnderson	SHoffman	APH	EAdensam
DATE	3/30/92	3/30/92	3/30/92	4/1/92

AMENDMENT NO. 87 TO FACILITY OPERATING LICENSE NO. NPF-8 - FARLEY, UNIT 2

Docket File
NRC PDR
Local PDR
PDII-1 Reading
S. Varga (14E4)
E. Adensam
P. Anderson
S. Hoffman
OGC
D. Hagan (MNBB 3302)
G. Hill (4) (P1-37)
Wanda Jones (P-130A)
C. Grimes (11E22)
J. Wiggins
E. Murphy
R. Jones
K. Desai
L. Cunningham
K. Eccleston
ACRS (10)
OPA
OC/LFMB
L. Reyes, RII

cc: Farley Service List

A copy of our related Safety Evaluation is also enclosed. A Notice of Issuance will be included in the Commission's bi-weekly Federal Register notice.

Sincerely,

Orignal signed by:

Stephen T. Hoffman, Project Manager
Project Directorate II-1
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Amendment No. 87 to NPF-8
2. Safety Evaluation

cc w/enclosures:
See next page

Distribution:
See attached page

OFC	PDII-1/LA	PDII-1/PM	OGC	PDII-1/D
NAME	PAnderson	SHoffman	APH	EAdensam
DATE	3/30/92	3/30/92	3/30/92	4/1/92

Mr. W. G. Hairston, III
Southern Nuclear Operating Company, Inc.

Joseph M. Farley Nuclear Plant

cc:

Mr. R. P. McDonald
President
Southern Nuclear
Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295

Mr. J. D. Woodard
Vice-President-
Farley Project
Southern Nuclear Operating
Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295

Mr. L. B. Long,
Vice President-Technical Services
Southern Nuclear Operating
Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295

Mr. D. N. Morey
General Manager - Farley Nuclear Plant
Southern Nuclear Operating
Company, Inc.
P. O. Box 470
Ashford, Alabama 36312

Mr. B. L. Moore
Manager, Licensing
Southern Nuclear Operating
Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295

Mr. J. W. McGowan
Manager, Safety Audit
and Engineering Review
Southern Nuclear Operating Company, Inc.
P. O. Box 1295
Birmingham, Alabama 35201-1295

James H. Miller, III, Esq.
Balch and Bingham
P. O. Box 306
1710 Sixth Avenue North
Birmingham, Alabama 35201

Claude Earl Fox, M.D.
State Health Officer
State Department of Public Health
State Office Building
Montgomery, Alabama 36130

Chairman
Houston County Commission
P. O. Box 6406
Dothan, Alabama 36302

Regional Administrator, Region II
U.S. Nuclear Regulatory Commission
101 Marietta Street, Suite 2900
Atlanta, Georgia 30323

Resident Inspector
U.S. Nuclear Regulatory Commission
P. O. Box 24 - Route 2
Columbia, Alabama 36319

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

SOUTHERN NUCLEAR OPERATING COMPANY, INC.

DOCKET NO. 50-364

JOSEPH M. FARLEY NUCLEAR PLANT, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 87
License No. NPF-8

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Southern Nuclear Operating Company, Inc. (Southern Nuclear), dated February 20, 1992, as supplemented on March 27, 1992, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this license amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications, as indicated in the attachment to this license amendment; and paragraph 2.C.(2) of Facility Operating License No. NPF-8 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 87 , are hereby incorporated in the license. Southern Nuclear shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Elinor G. Adensam

Elinor G. Adensam, Director
Project Directorate II-1
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: April 1, 1992

ATTACHMENT TO LICENSE AMENDMENT NO. 87

FACILITY OPERATING LICENSE NO. NPF-8

DOCKET NO. 50-364

Replace the following pages of the Appendix A Technical Specifications with the enclosed pages. The revised areas are indicated by marginal lines.

Remove Pages	Insert Pages
3/4 4-12	3/4 4-12
-	3/4 4-12a
3/4 4-17	3/4 4-17
-	3/4 4-17a
B3/4 4-3	B3/4 4-3
B3/4 4-3a	B3/4 4-3a
-	B3/4 4-3b

SURVEILLANCE REQUIREMENTS (Continued)

4.4.6.4 Acceptance Criteria

a. As used in this Specification:

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

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

3. Degraded Tube means a tube, including the sleeve if the tube has been repaired, that contains imperfections greater than or equal to 20% of the nominal wall thickness caused by degradation.

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

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

6. Plugging or Repair Limit means the imperfection depth at or beyond which the tube shall be repaired (i.e., sleeved) or removed from service by plugging and is greater than or equal to 40% of the nominal tube wall thickness. This definition does not apply to the area of the tubesheet region below the F* distance in the F* tubes. For a tube that has been sleeved with a mechanical joint sleeve, through wall penetration of greater than or equal to 31% of sleeve nominal wall thickness in the sleeve requires the tube to be removed from service by plugging. For a tube that has been sleeved with a welded joint sleeve, through wall penetration greater than or equal to 37% of sleeve nominal wall thickness in the sleeve between the weld joints requires the tube to be removed from service by plugging. At tube support plate intersections, the repair limit for the Ninth Operating Cycle is based on maintaining steam generator tube serviceability as described below:

   a. An eddy current examination using a bobbin probe of 100% of the hot and cold leg steam generator tube support plate intersections will be performed for tubes in service.

   b. Degradation within the bounds of the tube support plate with bobbin voltage less than or equal to 1.0 volt will be allowed to remain in service.

   c. Degradation within the bounds of the tube support plate with a bobbin voltage greater than 1.0 volts will be repaired or plugged except as noted in 4.4.6.4.a.6.d below.

d. Indications of potential degradation within the bounds of the tube support plate with a bobbin voltage greater than 1.0 volt but less than or equal to 3.6 volts may remain in service if a rotating pancake coil probe (RPC) inspection does not detect degradation. Indications of degradation with a bobbin voltage greater than 3.6 volts will be plugged or repaired.

7. Unserviceable describes the condition of a tube or sleeve if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 4.4.6.3.c, above.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg. For a tube that has been repaired by sleeving, the tube inspection should include the sleeved portion of the tube.

9. Tube Repair refers to mechanical sleeving, as described by Westinghouse report WCAP-11178, Rev. 1, or laser welded sleeving, as described by Westinghouse report WCAP-12672, which is used to maintain a tube in service or return a tube to service. This includes the removal of plugs that were installed as a corrective or preventive measure.

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.7.2 Reactor Coolant System leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE,

b. 1 GPM UNIDENTIFIED LEAKAGE,

c. For the Ninth Operating Cycle only, primary-to-secondary leakage through all steam generators shall be limited to 450 gallons per day and 150 gallons per day through any one steam generator.

   For subsequent cycles, 1 GPM total primary-to-secondary leakage through all steam generators and 500 gallons per day through any one steam generator,

d. 10 GPM UNIDENTIFIED LEAKAGE from the Reactor Coolant System, and

e. 31 GPM CONTROLLED LEAKAGE at a Reactor Coolant System pressure of 2235 ± 20 psig.

f. The maximum allowable leakage of any Reactor Coolant System Pressure Isolation Valve shall be as specified in Table 3.4-1 at a pressure of 2235 ± 20 psig.

APPLICABILITY: MODES 1, 2, 3 and 4

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any Reactor Coolant System leakage greater than any one of the above limits, excluding PRESSURE BOUNDARY LEAKAGE, reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With any Reactor Coolant System Pressure Isolation Valve leakage greater than the limit specified in Table 3.4-1, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least two closed manual or deactivated automatic valves, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.7.2.1 Reactor Coolant System leakages shall be demonstrated to be within each of the above limits by:

a. Monitoring the containment atmosphere particulate radioactivity monitor at least once per 12 hours.

b. Monitoring the containment air cooler condensate level system or containment atmosphere gaseous radioactivity monitor at least once per 12 hours.

3/4.4.6 STEAM GENERATORS

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 result in negligible 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 limitation of steam generator tube leakage between the primary coolant system and the secondary coolant system (primary-to-secondary leakage = 500 gallons per day per steam generator). Cracks having a primary-to-secondary leakage less than this limit during operation will have an adequate margin of safety to withstand the loads imposed during normal operation and by postulated accidents. Operating plants have demonstrated that primary-to-secondary leakage of 500 gallons per day per steam generator can readily be detected by radiation monitors of steam generator blowdown. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged or repaired.

For the Ninth Operating Cycle only, the repair limit for tubes with flaw indications contained within the bounds of a tube support plate has been provided to the NRC in Southern Nuclear Operating Company letter dated February 20, 1992. The repair limit is based on the analysis contained in WCAP-12871, Revision 2, "J. M. Farley Units 1 and 2 SG Tube Plugging Criteria for ODSCC at Tube Support Plates." The application of this criteria is based on limiting primary-to-secondary leakage during a steam line break to less than 1 gallon per minute. Primary-to-secondary leakage during this cycle only is limited to 150 gallons per day per steam generator during normal operation.

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 or repair will be required for all tubes with imperfections exceeding 40% of the tube nominal wall thickness. If a sleeved tube is found to have through wall penetration of greater than or equal to 31% for the mechanical sleeve and 37% for the laser welded sleeve of sleeve nominal wall thickness in the sleeve, it must be plugged. The 31% and 37% limits are derived from R.G. 1.121 calculations with 20% added for conservatism. The portion of the tube and the sleeve for which indications of wall degradation must be evaluated can be summarized as follows:

a. Mechanical

1. Indications of degradation in the entire length of the sleeve must be evaluated against the sleeve plugging limit.

2. Indication of tube degradation of any type including a complete guillotine break in the tube between the bottom of the upper joint and the top of the lower roll expansion does not require that the tube be removed from service.

3. The tube plugging limit continues to apply to the portion of the tube in the entire upper joint region and in the lower roll expansion. As noted above the sleeve plugging limit applies to these areas also.

4. The tube plugging limit continues to apply to that portion of the tube above the top of the upper joint.

b. Laser Welded

1. Indications of degradation in the length of the sleeve between the weld joints must be evaluated against the sleeve plugging limit.

2. Indication of tube degradation of any type including a complete break in the tube between the upper weld joint and the lower weld joint does not require that the tube be removed from service.

3. At the weld joint, degradation must be evaluated in both the sleeve and tube.

4. In a joint with more than one weld, the weld closest to the end of the sleeve represents the joint to be inspected and the limit of the sleeve inspection.

5. The tube plugging limit continues to apply to the portion of the tube above the upper weld joint and below the lower weld joint.

F* tubes do not have to be plugged or repaired provided the remainder of the tube within the tubesheet that is above the F* distance is not degraded. The F* distance is equal to 1.79 inches and is measured down from the top of the tubesheet or the bottom of the roll transition, whichever is lower in elevation. Included in this distance is an allowance of 0.25 inch for eddy current elevation measurement uncertainty.

Steam generator tube inspections of operating plants have demonstrated the capability to reliably detect wastage type 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 reported to the Commission pursuant to 10 CFR 50.73 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 to the Technical Specifications, if necessary.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 87 TO FACILITY OPERATING LICENSE NO. NPF-8

SOUTHERN NUCLEAR OPERATING COMPANY, INC.

JOSEPH M. FARLEY NUCLEAR PLANT, UNIT 2

DOCKET NO. 50-364

1.0 INTRODUCTION

By letter dated February 20, 1992, as supplemented on March 27, 1992 (Reference 7), Southern Nuclear Operating Company, Inc. (the licensee), submitted a request for changes to the Joseph M. Farley Nuclear Plant (Farley), Unit 2, Technical Specifications. The requested amendment revises Technical Specifications 4.4.6.4 and 3.4.7.2, and Bases 3/4.4.6 to allow the implementation of interim steam generator (SG) tube plugging criteria for the tube support plate (TSP) elevations. The amendment also reduces the allowed primary-to-secondary operational leakage from any one SG from 500 gallons per day (gpd) to 150 gpd. The total allowed primary-to-secondary operation leakage from all three SGs is reduced from one gallon per minute (gpm), which is 1440 gpd, to 450 gpd. Leakage subsequent to a main steamline break (SLB) accident is not expected to exceed the currently postulated value of one gpm. The March 27, 1992, letter provided clarifying information that did not change the initial proposed no significant hazards consideration determination.

2.0 BACKGROUND

Previous inservice inspections and examinations of the SG tubes at Farley, Units 1 and 2, have identified extensive intergranular stress corrosion cracking (IGSCC) on the outer diameter of the tubes at the TSP intersections. The licensee refers to this particular form of IGSCC as outer diameter stress corrosion cracking (ODSCC).

ODSCC activity at TSP intersections is a common degradation phenomenon in SGs in nuclear power plants. Approximately 21 tubes, including 57 tube-to-TSP intersections, have been removed from affected SGs across the industry for examination and testing. These include one tube from Farley, Unit 1, (including 1 TSP intersection) and seven tubes from Farley, Unit 2, (13 TSP intersections). Each of these pulled tube TSP intersections was sectioned and metallographically examined. In general, these examinations have revealed multiple, segmented, axial cracks with short lengths for the deepest penetrations. The ODSCC is generally confined to within the thickness of the TSPs, consistent with the corrosion mechanism which involves the concentration of impurities, including caustics, in the tube-to-TSP crevices. The staff notes that there is some potential for shallow ODSCC for a short distance above or below the TSP. This has been observed for two of the pulled TSP intersections, including one from Farley, Unit 1, which exhibited short, very shallow ($\leq$10%) crack segments extending 0.25 inch above the TSP.

The pulled tube specimens from Farley, Units 1 and 2, to date have shown minimal intergranular attack (IGA) involvement with the ODSCC. However, more significant IGA involvement has been observed on some pulled tube specimens from other plants. These results suggest that the degradation develops as IGA plus SCC, particularly when maximum IGA depths greater than 25% are found. A large number (>100) of axial cracks around the circumference are commonly found on these tubes. The maximum depth of IGA is typically 1/2 to 1/3 of the stress corrosion cracking (SCC) depth. Patches of cellular IGA/ODSCC formed by combined axial and circumferential orientation of microcracks are frequently found in pulled tube examinations. The staff notes, however, that the axial crack segments have been the dominant flaw feature affecting the structural integrity of the pulled tube specimens as evidenced by results of burst tests (discussed in Section 4.3), performed for 29 of the pulled TSP intersections prior to sectioning.

Technical Specification 4.4.6.4.a.6, Plugging or Repair Limit, requires that tubes with imperfections exceeding 40% of the nominal tube wall thickness be repaired by sleeving or removed from service by plugging. The licensee stated that this repair criterion would result in unnecessary removal of significant numbers of SG tubes from service. To preclude this, the licensee developed proposed alternative plugging criteria (APC) that was submitted by letter dated February 26, 1991 (Reference 1). This proposal was revised by letter dated November 13, 1991 (Reference 2), (1) to respond to questions and comments from the Nuclear Regulatory Commission staff (the staff) transmitted by letter dated August 8, 1991 (Reference 3), and (2) to reflect additional pulled tube information from the Trojan Nuclear Plant. The proposed APC involves a voltage amplitude limit of 4 volts, as measured by the industry standard eddy current bobbin probe (referred to herein as a bobbin) using the 400/100 KHz mix differential channel, in lieu of the current 40% depth-based plugging or repair limit. These criteria would only apply to ODSCC degradation confined to within the thickness of the TSPs.

Staff comments and questions concerning the November 13, 1991, APC proposal (Reference 2) were provided by letter dated January 29, 1992 (Reference 4). The licensee responded to these questions and comments during a meeting on February 6, 1992. By letter dated February 20, 1992 (Reference 5), the licensee submitted an updated technical support document for the APC, WCAP-12871, Revision 2 (Reference 6). WCAP-12871, Revision 2, is intended to support a 3.6 volt repair limit; however, the licensee has not yet revised its 4.0 volt APC proposal in Reference 2.

In their February 20, 1992, letter (Reference 5), the licensee requested interim modifications to the tube repair limits and primary-to-secondary leakage limits in the Farley, Unit 2, Technical Specifications for the ninth operating cycle only, pending completion of the staff's review of the APC proposal. The proposed modifications to the tube repair limits are described in detail in Section 3.0 of this Safety Evaluation, and include a 1 volt repair criterion for flaws confined to the thickness of the TSP in lieu of the currently applicable depth-based limit of 40%. The proposed modifications to the leakage limits, described in Section 4.0 of this Safety Evaluation are more restrictive than the present limits.

3.0 TECHNICAL SPECIFICATION CHANGES

Farley, Unit 2, Technical Specification 4.4.6.4.a.6, Plugging or Repair Limit, and Bases 3/4.4.6, Steam Generators, are revised to specify that the repair limit at the TSP intersections for the ninth operating cycle is based on the analyses in WCAP-12871, Revision 2, to maintain SG tube serviceability as described below:

a. An eddy current inspection using a bobbin of 100% of the hot and cold leg SG TSP intersections will be performed for tubes in service.

b. Degradation within the bounds of the TSP with a bobbin voltage less than or equal to 1.0 volt will be allowed to remain in service.

c. Degradation within the bounds of the TSP with a bobbin voltage greater than 1.0 volt will be repaired or plugged except as noted in d. below.

d. Indications of potential degradation within the bounds of the TSP with a bobbin voltage greater than 1.0 volt, but less than or equal to 3.6 volts, may remain in service if a rotating pancake coil probe (RPC) inspection does not detect degradation. Indications of degradation with a bobbin voltage greater than 3.6 volts will be plugged or repaired.

Farley, Unit 2, Technical Specification 3.4.7.2, and Bases 3/4.4.6 are revised to specify that for the ninth operating cycle only, primary-to-secondary leakage through all SGs shall be limited to 450 gpd and 150 gpd through any one SG. Primary-to-secondary leakage during a steam line break (SLB) will not exceed the current Technical Specification basis of 1 gpm.

4.0 EVALUATION

4.1 Inspection Issues

In support of the proposed interim repair limit, the licensee proposes to utilize the eddy current test guidelines provided in Attachment 7 of the February 20, 1992, letter (Reference 5) to ensure the field bobbin indication voltage measurements are obtained in a manner consistent with how the voltage limit was developed. These guidelines define the bobbin specifications, calibration requirements, specific acquisition and analyses criteria, and flaw recording guidelines to be used for the inspection of the SGs. The staff finds these guidelines to be consistent with the Westinghouse NDE [non-destructive examination] Data Acquisition and Analysis Guidelines recommended in WCAP-12871 (Reference 6). However, the guidelines contained in the licensee's February 20, 1992, letter (Reference 5, Attachment 7) specify that bobbin indications exceeding 1.0 volt will be recorded. The staff notes that knowledge of the voltage distribution of indications being accepted for continued service (i.e., bobbin indications equal to or less than 1.0 volt), is an integral element of the technical justification being proposed by the licensee in support of the interim repair limit, as discussed in Section 3.5. At the staff's request, the licensee agreed in their March 27, 1992, submittal (Reference 7) to record all flaw indications regardless of voltage amplitude. With this commitment, the staff finds the licensee's eddy current test guidelines to be acceptable.

The staff finds that the proposed 100% bobbin inspection program is consistent with the development of voltage based repair limits; namely the establishment of a relationship between burst pressure and bobbin voltage. In addition, the licensee states in their February 20, 1992, submittal (Reference 5) that it will perform an RPC sample inspection of 100 tubes, including all tubes with dent indications exceeding 5 volts as measured by the bobbin, and TSP intersections with artifact indications or indications with unusual phase angles. The RPC can provide improved resolution of flaw indications (as compared to the bobbin), in the presence of dents and artifacts and is sensitive to both axial and circumferential flaws. The licensee states that the sampling plan will be expanded as necessary, based on the nature and number of the flaws discovered. At the staff's request, the licensee stated in the March 27, 1992, submittal (Reference 7) that RPC flaw indications not found by the bobbin due to masking effects (e.g., denting, artifact indications, and noise), will be plugged or repaired. In addition, tubes with greater than 5 volt dent indications (as measured with the bobbin), will be plugged or repaired if they are found to contain RPC flaw indications.

The Farley eddy test guidelines state that all TSP intersections exhibiting a bobbin indication exceeding 1.0 volt are to be inspected with an RPC. The RPC inspections will permit better characterization of the indications found by bobbin to verify the applicability of the proposed interim repair limit. The proposed repair limit is based on the premise of axially oriented ODSCC as the dominant degradation mechanism with some IGA involvement. The proposed repair limit is also based on the premise that any significant degradation is confined to the TSP. At the staff's request, the licensee agreed in their March 27, 1992, letter (Reference 7) to inform the staff prior to Cycle 9 operation of any unexpected RPC findings relative to the assumed characteristics of the flaws at the TSPs. This includes any detectable circumferential indications or detectable indications extending outside the thickness of the TSP. The licensee's safety evaluation of these unexpected findings will also be provided.

4.2 Tube Integrity Issues

The purpose of the Technical Specification tube repair limits is to ensure that tubes accepted for continued service will retain adequate structural and leakage integrity during normal operating, transient, and postulated accident conditions, consistent with General Design Criteria 14, 15, and 31 of 10 CFR Part 50, Appendix A. Structural integrity refers to maintaining adequate margins against gross failure, rupture, and collapse of the SG tubing. Leakage integrity refers to limiting primary-to-secondary leakage to within acceptable limits. The traditional strategy for accomplishing these objectives has been to establish a minimum wall thickness requirement in accordance with the structural criteria of Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes." Allowance for eddy current measurement error and flaw growth between inspections has been added to the minimum wall thickness requirement (consistent with the Regulatory Guide) to arrive at a depth-based repair limit. Enforcement of a minimum wall thickness requirement would implicitly serve to ensure leakage integrity (during normal operation and accidents), as well as structural integrity. It has been recognized, however, that defects, especially cracks, will occasionally grow entirely through-wall and develop small leaks. For this reason, tight limits on allowable primary-to-secondary leakage have been established in the Technical Specifications to ensure timely plant shutdown before adequate structural and leakage integrity of the affected tube is impaired.

The proposed tube repair limits for Farley, Unit 2, consist of voltage amplitude criteria rather than the traditional depth-based criteria. Thus, the proposed repair criteria represent a departure from the past practice of explicitly enforcing a minimum wall thickness requirement.

The pulled tube examinations show that for bobbin indications at or near 1 volt (i.e., the proposed interim limit) maximum crack depths range between 20% and 98% through-wall. The likelihood of through-wall or near through-wall crack penetrations appears to increase with increasing voltage amplitude. For indications at or near 3.6 volts (i.e., the APC limit), the maximum crack depths have been found to range between 90% and 100% through-wall. Clearly, many of the tubes which will be found to contain "non-repairable" indications under the proposed interim criteria may develop through-wall and near through-wall crack penetrations during the upcoming cycle, thus creating the potential for leakage during normal operation and postulated SLB accidents. The staff's evaluation of the proposed repair criteria from a structural and leakage integrity standpoint is provided in this Safety Evaluation in Sections 4.3 and 4.4, respectively.

4.3 Structural Integrity

4.3.1 Burst Integrity

The licensee has developed a burst strength/voltage correlation to demonstrate that bobbin indications satisfying the proposed 1.0 volt interim repair criterion or the 3.6 volt APC criterion will retain adequate structural margins during Cycle 9 operation, consistent with the criteria of Regulatory Guide 1.121. The burst strength/voltage correlation includes the burst pressure versus field bobbin voltage data (pre-pull values), for twenty-nine pulled tube TSPs, including 3 TSPs from Farley, Unit 2. These pulled tube data are supplemented by 30 data points from laboratory tube specimens containing ODSCC flaws produced in model boiler tests under simulated field conditions. The bobbin voltage data used to construct the burst pressure/voltage correlation have been normalized to reflect calibration standard voltage setups and voltage measurement procedures consistent with the NDE Data Acquisition and Analysis Guidelines in WCAP-12871, Revision 2, Appendix A (Reference 6). The staff finds that this normalization ensures consistency among the voltage data in the burst pressure/voltage correlation and, in addition, ensures consistency between the voltage data in the correlation and the field voltage measurements at Farley, Unit 2.

The most limiting burst pressure criterion of Regulatory Guide 1.121 is that degraded tubes shall retain a margin of 3 against burst at normal operating differential pressure across the tube. For Farley, Unit 2, this translates to a limiting burst pressure criterion of 4380 psi. From the burst pressure/voltage correlation, the maximum voltage which will satisfy this burst pressure criterion at a 95% confidence intervals is 6.2 volts. The 3.6 volt APC limit, which WCAP-12871 is intended to support, includes an allowance for 20% NDE measurement uncertainty and for a 50% increases in voltage during the next operating cycle. The NDE measurement uncertainty estimate considered measurement uncertainties stemming from bobbin design characteristics, bobbin wear (which affects centering), variability among American Society of Mechanical Engineers (ASME) calibration standards, and variability in the analysts' interpretation of the signal voltage. The staff concurs that the NDE Data Acquisition and Analysis Guidelines (Reference 6, Appendix A), which have been incorporated into the Farley, Unit 2, eddy current test guidelines, will be effective in minimizing the uncertainties as they apply to the interim criteria. Based on implementation of these guidelines, a cumulative probability distribution of the residual measurement uncertainty (applicable to each bobbin indication), has been developed. The assumed 20% uncertainty in the voltage measurements is conservative with respect to the upper 95% cumulative probability value of 16% as determined from the cumulative probability distribution.

Potential flaw growth between inspections has been evaluated based on observed voltage amplitude changes during Cycles 6 and 7 at Farley, Unit 2. Specifically, the eddy current data from the 1987 and 1989 inspections were reexamined for each indication reported during the most recent previous inspection in 1990, using a consistent data analysis procedure. This examination showed that many of the 1990 indications were traceable back to the 1987 and 1989 inspections. The average percent changes in voltage considering the entire data set, were 45% between 1987 and 1989 and 29% between 1989 and 1990. These averages conservatively treat negative voltage changes as zero changes. If the data set is restricted to voltage changes where the initial indication exceeded 0.7 volts, the average voltage changes are smaller, e.g., 10% between 1989 and 1990. The 50% average voltage growth allowance used to support the 3.6 volt APC limit is intended to provide margins for variation in future growth rates at Farley, Unit 2.

For any specific individual tube, NDE measurement uncertainty and/or voltage growth may exceed the values assumed in the above deterministic basis for the 3.6 volt APC repair limit, since the deterministic basis does not consider the tail of the voltage measurement and voltage growth distribution. In addition, burst pressure for some tubes may be less than the 95% confidence values in the burst pressure/voltage calculation. The licensee proposes that these uncertainties be directly accounted for by use of Monte Carlo methods to demonstrate that the probability of burst during SLB accidents is acceptably low for the distribution of voltage indications being left in service. Under this approach, the beginning-of-cycle (BOC) indications left in service are projected to the end-of-cycle (EOC) by randomly sampling the probability distributions for NDE uncertainties and voltage growth per cycle. For each EOC Monte Carlo sample of bobbin voltage, the burst pressure/voltage correlation is randomly sampled to obtain a burst pressure. 100,000 Monte

Carlo samples are performed for the BOC distribution. The probability of tube burst at SLB is obtained as the sum of the samples resulting in burst pressures less than the SLB pressure differential of 2650 psi divided by the number of times the distribution of indications left in service is sampled.

This kind of Monte Carlo analysis was performed for the distribution of indications found during the previous (i.e., 1990) inspection at Farley, Unit 2. This analysis indicated that implementation of a 3.6 volt repair criterion at that time would have yielded a conditional probability of burst, given an SLB, of about $3x10^{-5}$. The staff concurs that this is an extremely low probability, three orders of magnitude less than the value considered in a staff generic risk assessment for SGs (NUREG-0844). Over time, the number of indications found between 0 and 3.6 volts can be expected to increase.

Therefore, the APC proposal (involving the 3.6 volt repair criterion), includes a provision for determining the probability of burst at SLB conditions following each outage for indications left in service to confirm the continued adequacy of the repair criterion.

The staff is continuing to evaluate the technical basis for the proposed APC (i.e., 3.6 volt criterion). In the meantime, the staff concludes that the proposed 1.0 volt interim criterion will provide adequate assurance that tubes with indications which are accepted for continued service will meet the burst pressure criteria of Regulatory Guide 1.121. The staff notes that the bounding value of voltage growth/cycle at Farley, Units 1 and 2, since 1987 has not exceeded 2.6 volts. The staff estimates this 2.6 volts to represent a bounding value, assuming no increase in corrosion rates over what has been observed previously at Farley, Units 1 and 2. Assuming a 20% voltage measurement uncertainty (upper 95% confidence value determined by the licensee) for a 1.0 volt indication left in service, the EOC voltage is expected by the staff to be bounded by 3.8 volts. This is substantially below the 6.2 voltage limit evaluated by the licensee as the lower 95% confidence limit for meeting the most limiting burst pressure criterion (i.e., three times normal operating pressure differential).

Finally, the licensee is proposing as part of the interim repair criteria that indications with bobbin voltages greater than 1.0 volt, but less than or equal to 3.6 volts, remain in service if RPC inspection does not confirm the indication. The staff notes that short and/or relatively shallow cracks that are detectable by the bobbin may sometimes not be detectable by RPC, although the RPC is considered by the staff to be more sensitive to longer, deeper flaws which are of structural significance.

The staff further notes that burst strength is not a unique function of voltage, rather for a given voltage there is a statistical distribution of possible burst strengths as indicated in the burst pressure/voltage correlation. The staff concludes that burst pressures for bobbin indications which were not confirmed by RPC will tend to be at the upper end of the burst pressure distribution. The 3.6 volt cutoff, such that all bobbin indications would be plugged or repaired (with or without confirming RPC indications), provides additional assurance that all excessively degraded tubes will be removed from service. Thus, the staff finds the proposed exception to the 1.0 volt criterion to be acceptable.

4.3.2 Combined Accident Loadings

The licensee has evaluated the effects of combined safe shutdown earthquake (SSE) and loss-of-coolant accident (LOCA) loads and SSE plus SLB loads on tube integrity, consistent with the General Design Criterion 2 (GDC-2) of 10 CFR Part 50, Appendix A. A combined LOCA plus SSE must be evaluated for potential yielding of the TSPs which could result in subsequent deformation of the tubes. If significant tube deformation should occur, primary flow area could be reduced and postulated cracks in tubes could open up which might create the potential for in-leakage (i.e., secondary-to-primary), under LOCA conditions. In-leakage during LOCA would pose a potential concern since it may cause an increase in the core peak clad temperature (PCT).

The most limiting accident conditions for tube deformation considerations result from the combination of SSE and LOCA loads. The seismic excitation defined for SGs is in the form of acceleration response spectra at the SG supports. In the seismic analysis, the licensee has used generic response spectra which envelop the Farley-specific response spectra. A finite element model of the Series 51 SG was developed, and the analysis was performed using the WECAN computer program. The mathematical model consisted of three dimensional lumped mass, beam, and pipe elements as well as general matrix input to represent the piping and support stiffness. Interactions at the TSP shell and wrapper/shell connections were represented by concentric spring-gap dynamic elements. Impact damping was used to account for energy dissipation at these locations.

LOCA loads, developed as a result of transient flow following a postulated primary coolant pipe break, were calculated for five different pipe break locations. These included three large and two minor pipe breaks. The large pipe break locations evaluated were the SG inlet and outlet lines and the reactor coolant pump outlet line, while the minor pipe breaks analyzed were two branch line breaks. Prior qualification of the Farley, Unit 2, primary piping for leak-before-break requirements resulted in the limiting LOCA event being the break of a minor branch line. The licensee, however, has used the loads for the primary piping break as a conservative approximation. The principal tube loading during a LOCA is caused by the rarefaction wave in the primary fluid. This wave initiates at the postulated break location and travels around the tube U-bends. A differential pressure is created across the two legs of the tube which causes an in-plane horizontal motion of the U-bends and induces significant lateral loads on the tubes. The pressure time histories needed for creating the differential pressure across the tube are obtained from transient thermal-hydraulic analyses using the MULTIFLEX computer code. For the rarefaction wave induced loadings, the predominant motion of the U-bends is in the plane of the U-bend. Thus, the individual tube motions are not coupled by the anti-vibration bars and the structural analysis is performed using single tube models limited to the U-bend and the straight leg region over the top two TSP's.

In addition to the rarefaction wave loading discussed above, the tube bundle is subjected to bending loads during a LOCA. These loads are due to the shaking of the SG caused by the break hydraulics and reactor coolant loop motion. However, the resulting TSP loads from this motion are small compared to those due to the rarefaction wave induced motion.

To obtain the LOCA induced hydraulic forcing functions, a dynamic blowdown analysis is performed to obtain the system hydraulic forcing functions assuming an instantaneous (1.0 msec break opening time), double-ended guillotine break. The hydraulic forcing functions are then applied, along with the displacement time-history of the reactor pressure vessel (obtained from a separate reactor vessel blowdown analysis) to a system structural model that includes the SG, the reactor coolant pump and the primary piping. This analysis yields the time history displacements of the SG at its upper lateral and lower support nodes. These time-history displacements formulate the forcing functions for obtaining the tube stresses due to LOCA shaking of the SG.

In calculating a combined TSP load, the licensee combined the LOCA rarefaction and LOCA shaking loads directly, while the LOCA and SSE loads were combined using the square root of the sum of the squares. The staff found this combination methodology acceptable. The overall TSP load was transferred to the SG shell through wedge groups located at discrete locations around the plate circumference.

The radial loads due to combined LOCA and SSE could potentially result in yielding of the TSP at the wedge supports, causing some tubes in the vicinity of the wedge supports to be deformed. Utilizing results from recent tests and analysis programs, the licensee has shown that tubes will undergo permanent deformation if the change in diameter exceeds a minimum threshold value. This threshold for tube deformation is related to the concern for tubes with pre-existing tight cracks that could potentially open during a combined LOCA plus SSE event. For Farley, Unit 2, the LOCA plus SSE loads were determined to be of such magnitude that none of the tubes (which are assumed to contain pre-existing tight cracks) are predicted to exceed this deformation threshold value and, therefore, will not lead to significant tube leakage.

The licensee has assessed the effect of SSE bending stresses on the burst strength of tubes with axial cracks. Tensile stress in the tube wall would tend to close the cracks while compressive stress would tend to open the cracks. On the basis of previously performed tests, the licensee has concluded that the burst strength of tubes with through-wall cracking is not affected by an SSE event.

Based on a review of the information provided by the licensee, the staff concludes that at Farley, Unit 2, no significant tube deformation or leakage is likely to occur during an SSE plus LOCA event. In addition, burst strength of tubing with through-wall cracks is not affected by an SSE event.

4.4 Leakage Integrity

As discussed earlier, a number of the indications satisfying the proposed interim 1.0 volt repair limit can be expected to have or to develop through-wall and/or near through-wall crack penetrations during the next cycle, thus creating the potential for primary-to-secondary leakage during normal operation, transients, or postulated accidents. The staff finds that adequate leakage integrity during normal operating conditions is assured by the proposed restrictive Technical Specification limits on allowable primary-to-secondary leakage as discussed in Section 4.5 of this Safety Evaluation. Adequate leakage integrity during transients and postulated accidents is demonstrated by showing that for the most limiting accident, the resulting leakage will not exceed the rate assumed in the Farley, Unit 2, design basis analysis.

The licensee has identified the Final Safety Analysis Report (FSAR), Chapter 15, accidents which result in secondary steam release, and thus whose consequences could be affected by the extent of primary-to-secondary leakage. Of these accidents, the SLB was determined to be the most limiting. In this case, since the SG in the faulted loop is subject to dryout, the activity release path is conservatively assumed to be direct to the environment, without any mitigation resulting from mixing with secondary liquid coolant in the SG.

The licensee has submitted an analysis (Reference 6) in support of the APC (3.6 volt based criteria) proposal to demonstrate 55 gpm as the allowable leakage rate during SLB. This analysis is under staff review. For the purpose of supporting the interim repair limit proposal, the licensee has proposed that the maximum allowable leak rate during SLB be 1.0 gpm, consistent with the assumed leak rate in the FSAR design basis analysis. Therefore, there is no change in the offsite dose as a result of the use of the interim repair limit. The staff concurs that use of an accident leakage of 1.0 gpm is an acceptable leak rate limit.

The SLB leakage calculation model in Reference 6 utilizes a correlation between leakage test data obtained under simulated SLB conditions (at a given TSP location), and the corresponding normalized bobbin voltage (SLB leakage/voltage correlation). The SLB leakage data includes 27 data points from the model boiler specimens described earlier and 7 data points from the pulled tube specimens. The calculation method involves establishing the voltage distribution of the indications being accepted for continued service. Probability distributions of voltage measurement uncertainty, voltage growth/cycle, and SLB leak rate versus voltage are accounted for by Monte Carlo techniques in predicting the distribution of EOC voltages and the associated SLB leakage. One thousand Monte Carlo simulations of the BOC distribution of indications are performed. SLB leakage is evaluated at the 90% cumulative probability level.

Based on the voltage distributions found during previous inspection (1990) at Farley, Unit 2, and assuming implementation of the 3.6 volt repair criterion, the estimated leakage during a postulated SLB at EOC 8 was 0.4 gpm at the 90% cumulative probability level, well within the current licensing basis of 1.0 gpm. The estimate is almost entirely made up of leakage from indications whose BOC voltages were greater than 2 volts. Utilizing the same model, the licensee has determined that about 4000 BOC indications at 2 volts would be necessary to produce an SLB leak rate of 1.0 gpm (at 90% cumulative probability) at EOC.

In support of the 1 volt interim repair criterion, the licensee will update the above analyses to consider the distribution of voltages for indications satisfying the 1 volt criterion during the eighth refueling outage inspection. The analysis will also reflect the distribution of voltage changes observed during Cycle 8 (i.e., 1990 to 1992).

The licensee states in their February 20, 1992, letter (Reference 5) that if potential leakage during a postulated SLB from indications left in service is found to exceed 1 gpm, additional tubes will be plugged or repaired as necessary to satisfy the 1.0 gpm criterion. This is not acceptable to the staff. The staff's approval of the proposed interim repair limit is based on the licensee's being able to demonstrate that acceptance of all bobbin indications satisfying the 1.0 volt criterion will not create the potential for leakage in excess of the 1.0 gpm licensing basis for a postulated SLB. Plugging or repair of tubes meeting the 1.0 volt criterion is not permitted to meet the 1.0 gpm limit.

At the staff's request, the licensee has agreed in their March 27, 1992, letter (Reference 7) to report, prior to restart from the eighth refueling outage, the results of its SLB leakage analysis. This analysis shall confirm that the leakage from a postulated SLB at EOC 9 will not exceed 1.0 gpm.

4.5 Proposed Interim Leakage Limits

4.5.1 Description

The licensee is proposing an interim change to the reactor coolant system leakage limit criteria in Technical Specification 3.4.7.2 that is applicable to the ninth operating cycle only. Specifically, the licensee is proposing to reduce the current 500 gpd limit for primary-to-secondary leakage through any one SG to 150 gpd. In addition, the limit on total leakage through all SGs would be reduced from 1.0 gpm (1440 gpd) to 450 gpd. Leakage during a SLB would not exceed the current design basis of 1.0 gpm.

4.5.2 Discussion

The current 500 gpd limit per SG is intended to ensure that through-wall cracks which leak at rates up to this limit during normal operation will not propagate and result in tube rupture under postulated accident conditions consistent with the criteria of Regulatory Guide 1.121. The current 1.0 gpm limit for total primary-to-secondary leakage is consistent with the assumptions used in the FSAR design basis accident analyses.

Development of the proposed 150 gpd limit per SG has utilized the extensive industry data base regarding burst pressure as a function of crack length and leakage during normal operation. Based on leakage evaluated at the lower 95% confidence interval for a given crack size, the proposed 150 gpd limit would be exceeded before the crack length reaches the critical crack length for SLB pressures. Based on nominal, best estimate leakage rates, the 150 gpd limit would be exceeded before the crack length reaches the critical length for three times normal operating pressure.

The proposed interim change is more restrictive than the existing limits, and is intended to provide a greater margin of safety against rupture. The proposed interim limits are also intended to provide additional margin to accommodate a rogue crack which might grow at much greater than expected rates, or unexpectedly extend outside the thickness of the TSP, and thus provide additional protection against exceeding SLB leakage limits. The staff finds the proposed interim leakage limits to be acceptable.

4.6 Summary

Based on the above evaluation, the staff concludes that the proposed interim tube repair limits and leakage limits will ensure adequate structural and leakage integrity of the SG tubing at Farley, Unit 2, consistent with applicable regulatory requirements. The staff's approval of the proposed interim repair limit is based on the licensee's being able to demonstrate that acceptance of all indications satisfying the 1.0 volt criterion will not create the potential for leakage in excess of the 1.0 gpm licensing basis for a postulated SLB occurring at EOC 9. The licensee has agreed to report, prior to restart from the eighth refueling outage, the results of the SLB leakage analysis that confirms that the leakage during a postulated SLB at EOC 9 will not exceed 1.0 gpm.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the State of Alabama official was notified of the proposed issuance of the amendment. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (57 FR 7405). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

7.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (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.

8.0 REFERENCES

1. Alabama Power Company letter dated February 26, 1991, "Joseph M. Farley Nuclear Plant - Units 1 and 2, Steam Generator (SG) Tube Support Plate (TSP) Alternate Plugging Criteria (APC)."

2. Alabama Power Company letter, dated November 13, 1991, "Joseph M. Farley Nuclear Plant, Steam Generator (SG) Tube Support Plate (TSP) Alternate Plugging Criteria (APC)."

3. NRC letter to Alabama Power Company, dated August 8, 1991," Request for Additional Information Concerning Steam Generator Tube Support Plate Alternate Tube Plugging Criteria for Joseph M. Farley Nuclear Plant, Units 1 and 2."

4. NRC letter to Southern Nuclear Operating Company, dated January 29, 1992, "Steam Generator Tube Support Plate Alternate Plugging Criteria for Joseph Farley Nuclear Plant, Units 1 and 2."

5. Southern Nuclear Operating Company, Inc., letter, dated February 20, 1992, "Joseph M. Farley Unit 2, Steam Generator Tube Support Plate Interim Plugging Criteria," February 1992.

6. Westinghouse Reports WCAP-12871, Revision 2 (Proprietary Version) and WCAP-12872, Revision 2 (Non-Proprietary Version), "J.M. Farley Units 1 and 2 SG Tube Plugging Criteria for ODSCC at Tube Support Plates."

7. Southern Nuclear Operating Company, Inc. letter, dated March 27, 1992, "Joseph M. Farley Nuclear Plant - Unit 2 Interim Plugging Criteria."

Principal Contributor: E. Murphy
K. Desai
J. Rajan

Date: April 1, 1992

ADR/3 ROSTER

ASSISTANT DIRECTOR for REGION III		Mail Stop 13-H-24		PLANT	BACKPM
ZWOLINSKI, John A.	504-1335	Room	13-H-22		
LEEDS, Eric J.	504-1336		13-H-23		
WIENS, Carilyn (Sue)	504-1335		13-H-24		
PROJECT DIRECTORATE III-1		Mail Stop	13-D-18		
MARSH, Ledyard (Tad)	504-1340	Room	13-D-18		
DELGADO, Jessie	504-1340		13-D-17		
YINGLING, Dana	504-1340		13-D-20		
*CARPTENER, Gene	504-1347	PE	13-C-17		
COLBURN, Timothy G.	504-1341		13-D-19	Fermi	B. Stransky
DIEC, David	504-1386		13-F-19	(INTERN)	
GAMBERONI, Marsha	504-3024	PE	13-C-22		
LONG, William	504-3026		13-D-15	Monticello/ Prairie Island	A. Masciantonio
MASCIANTONIO, Armand	504-1337		13-G-22	Palisades	M.Gamberoni
SHUTTLEWORTH, Peggy	504-1333	LA	13-G-20		
STRANSKY, Robert	504-1346		13-D-16	Big Rock	J. Stang
STANG, John F.	504-1345		13-D-14	DC Cook	W. Long
PROJECT DIRRECTORATE III-2		Mail Stop	13-D-1		
BARRETT, Richard J.	504-1395	Room	13-D-1		
AUSTIN, Tammy	504-1395		13-D-6		
REINHART, Jeannie	504-1395		13-D-1		
ELLIOTT, Robert	504-1397	PE	13-C-11		
HICKMAN, John	504-3017		13-C-7	Zion	R. Pulisfer
HSIA, Tony	504-3028		13-D-11	Byron	C. Patel
LYNCH, Dave	504-3023	PE	13-D-5		
MOORE, Christy	504-3100	LA	13-D-12		
OLSHAN, Leonard N.	504-3018		13-D-8	Quad Cities	B. Siegel
PATEL, Chandu P.	504-3025		13-D-10	Zion	R. Pulisfer
PULISFER, Robert	504-3016		13-C-9	Braidwood	T. Hsia
SIEGEL, Byron	504-3019		13-D-7	Dresden/ LaSalle	R. Elliott
ORDAZ, Vonna	504-1391		13-F-19	(INTERN)	
PROJECT DIRECTORATE III-3			Mail Stop 13-E-21		
HANNON, John N.	504-1389		13-E-19		
JONES, Brenda	504-1389		13-E-21		
TORO, Elaine	504-1389		13-E-24 (2 days per week)		
** GODY, Anthony	504-1387		13-E-20	Clinton	C. Shiraki
HALL, Randy	504-3063		13-F-21	Perry	J. Hopkkins
HANSEN, Allen	504-1390		13-E-22	Kewanee	R. Samworth
HOPKINS, Jon	504-3027		13-D-13	Davis/Besse	A. Hansen
KREUTZER, Pat	504-1392	LA	13-F-23		
LOMBARDO, Jim	504-1221	PE	13-E-10		
SAMWORTH, Robert	504-1364		13-E-9	Point Beach	A. Hansen
SHIRAKI, Clyde	504-3101		13-D-9	Duane Arnold	R. Hall
WHARTON, Ray	504-1386		13-C-13	Callaway	T. Gody

*G. Carpenter (PM) for Clinton 4/17-8/3 (Can be reached on 504-1387)
**T. Gody on rotational to RV 4/17-8/3
REVISED 4/8/92