NUREG-1038
Supplement No. 3

Safety Evaluation Report
related to the operation of Shearon Harris Nuclear Power Plant, Unit No. 1

Docket No. STN 50-400

Carolina Power and Light Company
North Carolina Eastern Municipal Power Agency

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulatic

May 1986

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ABSTRACT

This report, Supplement No. 3 to the Safety Evaluation Report for the application filed by the Carolina Power and Light Company and North Carolina Eastern Municipal Power Agency (the applicants) for a license to operate the Shearon Harris Nuclear Power Plant Unit 1 (Docket No. 50-400), has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. This supplement reports the status of certain items that had not been resolved at the time of publication of the Safety Evaluation Report and Supplement Nos. 1 and 2.

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1 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 Introduction

In November 1983, the U.S. Nuclear Regulatory Commission staff (NRC staff or staff) issued a Safety Evaluation Report (SER), NUREG-1038, regarding the application by Carolina Power and Light Company and North Carolina Eastern Municipal Power Agency (the applicants) for a license to operate the Shearon Harris Nuclear Power Plant, Unit 1. Supplement Nos. 1 and 2 were issued in June 1984 and June 1985, respectively. This report is Supplement No. 3 to the SER.

This supplement provides more recent information regarding resolution of some of the open and confirmatory items identified in the SER and in Supplement Nos. 1 and 2.

Each of the following sections or appendices of this supplement is numbered the same as the section or appendix of the SER that is being updated, and the discussions are supplementary to and not in lieu of the discussion in the SER unless otherwise noted. Accordingly, Appendix A is a continuation of the chronology of NRC's principal actions related to the safety (or radiological) review of the application. Appendix B is an updated bibliography.* Appendix D is a list of abbreviations used in this supplement. Appendix E is a list of principal contributors to this supplement. Appendix H discusses the applicants' conformance to Regulatory Guide 1.97. Appendix I discusses the applicants' conformance to Generic Letter 83-28, Items 3.1.3 and 3.2.3. Section 15.8 of this supplement discusses the remaining items of Generic Letter 83-28. A concern was raised during an integrated design inspection in regard to the containment recirculation pumps. This matter has been resolved and is discussed in Section 6.2.2 of this supplement.

The Project Manager is Bart C. Buckley; he may be reached on (301) 492-9799.

1.7 Summary of Outstanding Issues

Section 1.7 in the SER and in Supplement Nos. 1 and 2 noted that certain information had not yet been provided by the applicants for several identified items. This supplement updates those items for which additional information has subsequently been provided. These items, and the sections of this supplement discussing the review conclusions, are

(1) Equipment qualification (3.10)

(2) Fire protection (9.5.1)

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*Availability of all material cited is described on the inside front cover of this report.

(3) Method of estimating noble gas activity from atmospheric steam dump valves (10.4.2, 11.5)

(4) Shift and relief turnover procedures (13.5.1)

(5) Shift supervisor responsibility (13.5.1)

(6) Control room access (13.5.1)

(7) Feedback of operating experience (13.5.1)

(8) Emergency support facilities (13.3.4)

The outstanding items given in Section 1.7 of the SER are listed in updated Table 1.2 with the current status given for each item. For items discussed in this supplement, the specific section is identified. The resolution of outstanding items that have not been resolved will be discussed in a future supplement to the SER.

Items 2, 3, 4, 5, 6, 7, and 8 above are now resolved; item 1 above remains open.

1.8 Confirmatory Issues

Section 1.8 of Supplement Nos. 1 and 2 to the SER stated that certain confirmatory information will be provided by the applicants. Seventeen of these items identified as items 1, 3, 4, 5, 7, 9, 11, 14, 15, 16, 18, 19, 20, 22, 23, 28, and 35 have been resolved in the cited sections of this supplement. The confirmatory items in Section 1.8 of the SER are listed in updated Table 1.3, which gives the current status of each item.

1.9 License Conditions

Section 1.9 of the SER and Supplement Nos. 1 and 2 listed several probable license conditions. License Condition 6, security plan adherence to regulations, and License Condition 9, physical security, of Table 1.4 of Supplement No. 2 are identical; consequently, License Condition 6 has been deleted. The license condition on steam generator tube rupture, delineated in Section 15.6.3 of Supplement No. 2, has been added to Table 1.4.

Table 1.2 Outstanding items

Item		Status	Section(s)
(1) Design of retaining wall		Resolved	2.5.5
(2) Missiles outside containment		Resolved	3.5.1.1
(3) Functional capability of Class 1 auxiliary piping systems		Resolved	3.9.3
(4) Control of minimum wall thickness in ASME Class 1, 2, and 3 piping systems		Resolved	3.9.3
(5) Equipment qualification		To be resolved	3.10, 3.11
(6) Preservice/Inservice Inspection Program		Changed to Confirmatory Item 34	5.2.4, 6.6
(7) Periodic testing of instrument air quality		Resolved	9.3.1
(8) Fire protection		Resolved	9.5.1
(9) Unmonitored release of condenser discharge during hogging operations		Resolved	10.4.2, 11.5
(10) Method of estimating noble gas activity from atmospheric steam dump valves		Resolved	10.4.2, 11.5
(11) Monitoring of all inputs to the service water system		Resolved	11.5
(12) Emergency preparedness		Resolved	13.3
(13) Steam generator tube rupture isolation time		Changed to Confirmatory Item 36	15.6.3
(14) TMI Action Plan Items (NUREG-0737 and Supplement No. 1 to NUREG-0737)			
I.A.1.2	Shift supervisor administrative duties	To be resolved	13.5.1
I.C.2	Shift and relief turnover procedures	Resolved	13.5.1
I.C.3	Shift supervisor responsibilities	Resolved	13.5.1

Table 1.2 (Continued)

Item		Status	Section(s)
I.C.4	Control room access	Resolved	13.5.1
I.C.5	Feedback of operating experience	Resolved	13.5.1
I.C.6	Verification of correct performance of operator activities	To be resolved	13.5.1
I.D.1	Control room design review	To be resolved	18
II.E.1.1	Auxiliary feedwater system reliability evaluation	Resolved	10.4.9
II.F.2	ICC instrumentation	Resolved	4.4.6
III.A.1.2	Emergency support facilities	Resolved	13.3.4
III.D.1.1	Leak reduction program	Resolved	9.3.5

Table 1.3 Confirmatory issues

Issue	Status	Section(s)
(1) Emergency plan meteorological program	Resolved	2.3.3
(2) Revision of FSAR Table 3.2.1-1	To be resolved	3.2.2
(3) Turbine missiles (see License Condition 1)	Resolved	3.5.1.3
(4) Design documentation of ASME components	Resolved	3.9.3.1
(5) Piping supports	Resolved	3.9.2
(6) Plant-specific submittal concerning testing of safety and relief valves	To be resolved	3.9.3.2
(7) Leak rate test program for pressure isolation valves (see item 29 in Table 16.1 of this supplement)	Resolved	3.9.6
(8) Calculation of ultimate strength capacity of containment building under uniform internal pressure	To be resolved	3.8
(9) Additional information on excore detectors (see item 30 in Table 16.1 of this supplement)	Resolved	4.3
(10) PORV setpoint values	To be resolved	5.2.2
(11) Revised pressure-temperature curves	Resolved	5.3.2
(12) Examination of steam generators and NUREG-1014 revisions	To be resolved	5.4.2.2
(13) Revision of FSAR on containment penetrations	To be resolved	6.2.4
(14) Additional information on adequacy of the ECCS during shutdown and startup	Resolved	6.3.5.1
(15) Design modifications for automatic reactor trip using shunt coil trip attachment	Resolved	7.2.2.4
(16) Solid-state logic protection system test circuit	Resolved	7.3.3.11
(17) Testing for remote shutdown operation	To be resolved	7.4.2.2
(18) RCS overpressure protection during low temperature operation	Resolved	7.6.2.2

Table 1.3 (Continued)

Issue	Status	Section(s)
(19) Adequacy of station electrical distribution	Resolved	8.4.2.3
(20) Use of load sequencer with offsite power	Resolved	8.4.7
(21) Compliance with Phase I and Phase II of NUREG-0612	To be resolved	9.1.5
(22) Pressure differential alarms	Resolved	9.4.5.2
(23) Emergency lighting	Resolved	9.5.3
(24) Radiation monitors for turbine building vent stack	Resolved	10.4
(25) Ability to continuously sample radioiodine and particulates (condenser vacuum pump effluent)	Resolved	10.4.2
(26) Location of high range noble gas monitors (turbine building vent)	Resolved	10.4.2, 10.4.3, 11.5
(27) Drawings for the filters handling sludge	Resolved	11.4.1
(28) Process Control Program	Resolved	11.4.1
(29) Polymer binder system	Resolved	11.4.1
(30) Radiation protection manager	Resolved	12.5
(31) Corporate management and technical support organization	To be resolved	13.1.1.6
(32) Initial test program • Additional testing to verify the capacity of the steam generator safety and relief valves • Amend FSAR to incorporate additional information on AWP endurance tests • Expansion of natural circulation tests to fully comply with NUREG-0737, Item I.G.1	To be resolved	14

Table 1.3 (Continued)

Issue	Status	Section(s)
(33) TMI Action Plan (NUREG-0737)		
I.C.7 NSSS vendor review process	To be resolved	13.5.2.3
II.K.3.5 Automatic trip of RCPs during LOCA	To be resolved	15.9.9
(34) Preservice/Inservice Inspection Program	To be resolved	5.2.4, 6.6
(35) Emergency preparedness	Resolved	13.3
(36) Steam generator tube rupture isolation time	To be resolved	15.6.3

Table 1.4 License conditions

License Condition	Section(s)
(1) Turbine system maintenance program	3.5.1.3
(2) Turbine steam valve maintenance	3.5.1.3
(3) II.B.3 Post-accident sampling system	9.3.2
(4) Processing of filter sludge in VR system	Deleted
(5) Operating experience	13.1.2.4
(6) Security plan adherence to regulations	Deleted
(7) Restriction above 90% power	Deleted (15.4.3, 4.3)
(8) II.F.2 Instrumentation for inadequate core cooling detection	4.4.6
(9) Physical security	13.6.3
(10) Steam generator tube rupture	15.6.3

2 SITE CHARACTERISTICS

2.3 Meteorology

2.3.3 Onsite Meteorological Measurements Program

In the SER, the staff stated that it would evaluate the emergency preparedness meteorological program during the Emergency Preparedness Implementation Appraisal (EPIA).

The staff reviewed the onsite meteorological measurements program to support emergency response during the EPIA. The evaluation of the meteorological program related to emergency response is contained in Section 4.2.1.4 of Inspection Report No. 50-400/85-09 (April 22, 1985).

The staff found the program adequate for use in emergency response situations. Several items concerning integration of offsite meteorological information in emergency response and concerning improved procedures related to atmospheric dispersion modeling were noted for program improvement. These items were tracked by Region II inspectors and subsequently closed in a followup inspection documented in Inspection Report No. 50-400/85-46 (December 17, 1985). All issues related to meteorological measurements in support of emergency response actions are considered closed. Therefore, Confirmatory Issue 1 is resolved.

3 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.9 Mechanical Systems and Components

3.9.3 ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures

3.9.3.1 Loading Combinations, Design Transients, and Stress Limits

In the SER, the staff stated that it had not completed its design specification review of select American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Class 1, 2, and 3 components. This issue was identified as Confirmatory Issue 4, "ASME Design Documentation." In letter NLS-85-338 from S. R. Zimmerman (CP&L) to H. R. Denton (NRC), dated September 26, 1985, the applicants provided information relative to Confirmatory Issue 4 in the form of responses to NRC staff Questions 210.78, 210.80, 210.81, and 210.82. On the basis of the audit conducted on selected pumps, valves, and piping systems, supplemented by a review of the information referenced above, the staff has concluded that the applicants' design specifications, design reports, and calculation files comply with ASME Code requirements and that adequate traceability exists in these documents relative to design commitments in the Final Safety Analysis Report (FSAR). Therefore, the staff considers Confirmatory Issue 4 resolved.

3.9.3.3 Component Supports

In the SER, the staff identified a confirmatory item concerning the design of component supports. In its review of the FSAR, the staff found that more detailed information was needed to review the design of ASME Code Class 1, 2, and 3 piping supports. The applicants provided responses to the staff in letters from M. A. McDuffie to H. Denton dated October 12 and November 15, 1983. In addition, several discussions were held between the applicants and staff to discuss the design criteria used for pipe supports. Because many of the pipe support designs were not complete at the time of the staff review and the design criteria appeared to be changing, the staff identified the design of pipe supports to be a confirmatory item in the SER. The staff stated in the SER that the applicants' submittals were acceptable contingent on a satisfactory finding from a design audit to be performed at the offices of the pipe support designers.

The design of the Shearon Harris pipe supports was being conducted by Bergen-Paterson (Hempstead, NY) at the time of the staff operating license review (early 1983). In mid-1983 the design of pipe supports was transferred to Ebasco Services, Inc (New York, NY). A CP&L site design group that was established in 1980 to resolve field changes is currently performing the final pipe support design and modifications with assistance from Ebasco as required.

The staff performed its audit on June 4-5, 1985, at the Shearon Harris plant site and reviewed the pipe support designs and design guidelines used by the CP&L site design group. One of the reasons for auditing the site group was that the staff had previously performed an integrated design inspection (IDI) at the offices of Ebasco in the pipe support area. Although the IDI team had also inspected the design guidelines used at the site, the staff audit focused on the conformance of the final design criteria used at the site to the commitments by the applicants in their October 12 and November 15, 1983, letters. Furthermore, the audit conducted at the site enabled the staff to view the final installed pipe support designs in the plant in order to gain a physical understanding of the different types of designs used.

The audit augmented the IDI effort and intentionally avoided a duplication of effort. Consequently, the audit included the following items:

(1) proper application of codes and standards to the design guidelines

(2) load combinations and stress limits in conformance with previous commitments

(3) conformance of final design guidelines to specific licensing commitments

(4) evaluation of specific pipe support design concerns identified in the plant walkdown

The pipe supports at Shearon Harris were designed in accordance with American National Standards Institute (ANSI) Standard B31.1, "Power Piping" (1973). ASME Code Subsection NF was used for the design of snubbers only. For supplementary steel, the designs followed American Institute of Steel Construction (AISC), Steel Construction Manual, (1969) (hereinafter called AISC Code), 7th Edition (the 8th Edition was used for section properties). The weld design followed the American Welding Society (AWS) D1.1, "Structural Welding Code" (1975) including the 1982 Edition for tubular steel. The staff accepts the use of ANSI B31.1 (supplemented by the AISC Code) as an appropriate standard for pipe supports for plants of this vintage design with certain adjustments to the AISC Code allowing for the differences between building steel and pipe support designs philosophy.

The staff reviewed the guidelines used by CP&L Harris Plant Engineering Section (HPES) for the design, modification, analysis, and verification of piping supports. The principle guidelines are included in the HPES Manual of Instructions, "Section 7.2.A (Piping Support/Restraint Design and/or Modification)." The staff reviewed the overall conformance of the design guidelines to the applicable codes and standards used for the pipe support design. The staff finds that the applicability of the codes and standards used for the pipe support designs is acceptable and that the conformance of the design guidelines to the appropriate codes and standards is adequate.

The staff reviewed the design guidelines for conformance to the licensing commitments made in the November 15, 1983, letter regarding the load combinations and stress limits to be used for pipe support design. The staff found that, for normal and upset system conditions (including the operating basis earthquake), the stresses were limited to the allowable stresses given in the AISC Code. For the emergency system condition (including the safe shutdown earthquake), the allowable stresses were increased by 33% as allowed by the AISC Code for seismic effects. However, Section 3.8.3 of the Standard Review Plan (SRP, NUREG-0800) does not allow a 33% increase for load combinations with operating-basis-earthquake loadings. For the faulted system condition, the allowable stresses were increased by 50%. This increase is consistent with the guidelines provided in SRP Section 3.8.3 for structural building steel. The increased stress allowable values are further limited so that the material yield stress is not exceeded.

On the basis of its review of the load combinations and stress limits, the staff concludes that the design limits used are in conformance with the applicable codes and consistent with staff requirements and licensing commitments and are, thus, acceptable.

The staff reviewed the design guidelines to verify that the specific design commitments made in the October 12 and the November 15, 1983, letters had been properly implemented in the design procedures.

In the October 12, 1983, letter, the applicants provided their deformation criteria as 1/16 in. for rigid frames and supports and 1/32 in. for frames using snubbers in the direction of loading. The IDI team found that two separate procedures provided a deflection criterion and that the two procedures were not consistent. The staff review found that the commitment made in the October 12, 1983, letter was consistent with the deflection check provided in CP&L Site Hanger Problem Resolution Guidelines, Revision 3, November 1, 1984. However, as concluded by the IDI team, a documentation change is required, but no reanalysis should be necessary because the ASME Code (and ANSI B31.1) does not provide explicit stiffness criteria.

In the November 15, 1983, letter, the applicants provided their buckling criterion. The maximum buckling stress was to be limited to two-thirds of the critical buckling stress. The critical buckling stress was defined as the Column Research Council column strength curve. The staff review of the design guidelines found that the buckling criterion was in accordance with the AISC Code and, therefore, was acceptable.

In the November 15, 1983, letter, the applicants stated that loads on concrete expansion anchors are limited to a 4 to 1 factor of safety on ultimate load (sleeve-type and self-drilling expansion anchors are not used at the plant). In its review of the design guidelines, the staff found this design commitment has been explicitly provided.

In the November 15, 1983, letter, the applicants stated that the loads on bolts are limited to the normal allowable loads in the AISC Code for the faulted condition. In its review of the design guidelines, the staff found this design commitment has been included. The loads on bolts are limited to normal allowable loads per the AISC Code for all service limits.

On the basis of its review of the design guidelines, the staff concludes that the specific design commitments made in the October 12 and November 15, 1983, letters had been properly implemented in the design procedures.

As a result of the audit, the staff raised several questions that were transmitted to the applicants in a letter from G. Knighton to S. Zimmerman dated October 25, 1985. The applicants responded in a letter from S. Zimmerman to H. Denton dated December 16, 1985. The staff has completed its review of the applicants' letter and finds that the responses adequately address the concerns raised by the staff on the basis of the actions taken by the applicants and the revisions made to the pipe support design guidelines.

As a result of its review of the applicants' submittals and on the basis of the results of the audit performed at the Shearon Harris site, the staff concludes that the specified design of ASME Code Class 1, 2, and 3 pipe supports at the Shearon Harris facility is acceptable. The staff conclusion is based on its review and audit finding that the applicants have met the requirements of Title 10 of the Code of Federal Regulations, Part 50 (10 CFR 50), Appendix A, General Design Criteria (GDC) 1, 2, and 4 with respect to the design and service load combinations and associated stress and deformation limits specified for ASME Code Class 1, 2, and 3 component supports by ensuring that component supports important to safety are designed to quality standards commensurate with their importance to safety, and that these supports can accommodate the effects of normal operation as well as postulated events such as loss-of-coolant accidents and the dynamic effects resulting from the safe shutdown earthquake. The combination of loadings (including system operating transients) considered for each component support within a system, including the designation of the appropriate service stress limit for each loading combination, has been found to be acceptable and in accordance with NUREG-0484. The specified design and service loading combinations used for the design of ASME Code Class 1, 2, and 3 component supports in systems classified as seismic Category I provide assurance that, in the event of an earthquake or other service loadings due to postulated events or system operating transients, the resulting combined stresses imposed on system components will not exceed allowable stress and strain limits for the materials of construction. Limiting the stresses under such loading combinations provides a conservative basis for the design of support components to withstand the most adverse combination of loading events without loss of structural integrity.

Thus, the staff considers Confirmatory Issue 5 as noted in SER Table 1.3 closed.

3.9.6 Inservice Testing of Pumps and Valves

In the SER, the staff indicated that the allowable leak rate limit for pressure isolation valves (PIVs) was to be no more than 1 gpm for each valve. Since that time, NRC has adopted a revised and less restrictive leak rate criterion for PIVs. The new acceptable leak rate is 1/2 gpm for each nominal inch of valve size up to a maximum of 5 gpm. The applicants chose to adopt this new criterion and have submitted Technical Specifications to the staff that reflect the new criterion. This is acceptable to the staff and resolves Confirmatory Issue 7.

3.10 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

3.10.1 Operability Qualification of Mechanical Equipment

3.10.1.1 Introduction

The NRC staff performs a two-step review of each applicant's pump and valve operability assurance program to determine whether the program can ensure that all pumps and valves important to safety will operate when required for the life of the plant under normal and accident conditions. The first step is a review of Section 3.9.3.2 of the applicant's FSAR. However, this information is general in nature and lacks sufficient detail to determine the scope of the overall equipment qualification program as it pertains to pump and valve operability. The results of the FSAR evaluation appear as input to the SER or a supplement. Any open SER issues are resolved before or concurrently with the onsite audit.

A Pump and Valve Operability Review Team (PVORT), consisting of consultants from a national laboratory and the NRC staff, conducts the second step, which consists of an audit of a representative sample of installed pump and valve assemblies and their supporting qualification documents at the plant site. On the basis of the results of both the audit and the FSAR review, the PVORT can determine whether the applicant's overall program conforms to the current licensing criteria in SRP Section 3.10. Conformance with SRP Section 3.10 is required to satisfy the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50 as well as Appendix B to 10 CFR 50.

The following sections include (1) a discussion of the PVORT review process, (2) the summary of PVORT findings concerning the applicants' overall pump and valve operability assurance program, (3) a discussion of the operability issues resulting from the PVORT review, (4) Table 3.1, which presents a summary of the audit results, and (5) Table 3.2, which presents a summary of the pump and valve operability SER issues and their status.

3.10.1.2 Discussion

The PVORT reviewed the pump and valve operability assurance information in Section 3.9.3.2 of the Shearon Harris FSAR and later conducted an onsite audit to determine the extent to which the pumps and valves important to safety meet the criteria listed above. The issues that resulted from the FSAR evaluation were summarized in the SER and were supplemented by specific comments discussed at a preaudit meeting on March 21, 1984. Several of these issues were adequately resolved by the applicants in a May 29, 1984, letter. The remaining issues were addressed and resolved during the onsite audit.

Table 3.2 summarizes the status of the SER items. The staff believes that the applicants have adequately clarified their position concerning these items and have committed to perform actions that should adequately address the concerns.

The onsite audit, which was conducted December 3 to 6, 1985, consisted of field observations of the equipment configuration and installation for a representative sample of plant equipment. The PVORT selected for evaluation four nuclear steam supply system (NSSS) and six balance of plant (BOP) pump and valve assemblies. Table 3.1 summarizes the status of each assembly that was audited. The field observations were followed by a review of the design and purchase specifications, test/analysis documents, and other documents related to equipment operability, which the applicants maintain in their central files. In addition to reviewing information concerning the selected assemblies, the PVORT also reviewed other information concerning the plant's overall equipment qualification program, including those programs and procedures necessary to ensure that equipment qualification issues and concerns will continue to be addressed for the life of the plant. One such program, concerning the deep draft pump issue (IE Bulletin 79-15), was reviewed in depth.

The PVORT resolved all but one of the specific operability concerns that were identified during the audit. The specific concern related to a 12-in. gate valve, 3CC-V165, which was qualified by analysis only. In addition, the applicants were informed of three generic issues to which they must respond before fuel load. These three generic issues are:

(1) The Shearon Harris FSAR does not contain a complete list of active valves.

(2) The preservice tests that are required before fuel load have not all been completed.

(3) Approximately 10% to 15% of all pumps and valves important to safety have not been completely qualified and installed.

The generic issues are confirmatory in nature and are discussed in Section 3.10.1.3.

Following the site audit, the applicants submitted a letter dated January 27, 1986, which resolved the one specific concern and addressed the three generic issues. The manner by which each confirmatory issue was addressed is briefly described in Section 3.10.1.3 and listed in Table 3.1.

However, a new generic confirmatory issue arose from the review of the January 27, 1986, submittal, and a discussion with the applicants followed on February 21, 1986. The concern is in regard to qualifying safety-related equipment by analysis only. To resolve this issue, the applicants shall be required to submit the appropriate information as requested in Section 3.10.1.3.

The PVORT believes that the applicants are dealing with the equipment qualification issue in a positive manner. All of the SER items were adequately resolved on the basis of additional clarifications and appropriate commitments provided by the applicants. During the audit the applicants addressed the questions posed by the PVORT and committed to resolve certain unresolved issues before fuel load. Furthermore, the applicants discussed significant aspects of their overall equipment qualification program, such as preventive maintenance and vibration analysis. Consequently, the PVORT believes that the continuous implementation of the applicants' overall program should provide adequate assurance that the pumps and valves important to safety will operate as required for the life of the plant.

3.10.1.3 Operability Issues

On the basis of PVORT's evaluation of the pump and valve operability assurance program, the staff has identified to the applicants the following operability issues that must be completed before fuel load:

(1) Specific Operability Issue

The 12-in. Velan gate valve (3CC-V165) was qualified by analysis only. The applicants should provide test data demonstrating the ability of this valve assembly to operate as required under its design load conditions. The applicants shall include a description of the test performed as well as the basis for establishing the similarity of the installed valve with the valve tested.

The applicants stated that valve 3CC-V165 is not required to operate until approximately 20 min following a large loss-of-coolant accident (LOCA).

During the worst postulated event (LOCA and safe shutdown earthquake (SSE)), the valve is normally closed and will not receive any LOCA loads, only SSE loads. Because the valve disc will already be pressed firmly against its seat, the applicants predict that the SSE loads will not adversely affect the functionality of the valve internals. This clarification of the valve's safety function plus the onsite review of the valve assembly analysis and valve actuator test reports provide confidence that valve 3CC-V165 will function as required. Therefore, the specific issue for this valve is considered closed. However, a telephone conference was held on February 21, 1986, with the applicants, and it was apparent that the other safety-related equipment also may have been qualified by analysis only. The staff considers this concern a generic confirmatory issue that the applicants must resolve by submitting appropriate information for staff review and approval.

(2) Generic Confirmatory Issues

(a) At the conclusion of the PVORT audit, it was apparent that a complete list of active valves had not been provided in the FSAR. The applicants should confirm that all active valves are correctly identified in the FSAR.

In the letter of January 27, 1986, the applicants committed to revise the FSAR table by the completion of the pump and valve operability review.

(b) At the time of the audit, most construction tests had already been completed. However, the hot functional tests were scheduled to commence later in the month. The applicants shall confirm that all preservice tests that are required before operation have been completed.

In the letter of January 27, 1986, the applicants committed to complete preservice testing before power operation.

(c) At the time of the audit, approximately 10% to 15% of all pumps and valves important to safety had not been qualified. The applicants shall confirm that all pumps and valves important to safety are properly qualified and installed. In addition, the applicants shall provide written confirmation that the original loads used in tests or analyses to qualify pumps and valves important to safety are not exceeded by any new loads, such as those imposed by a LOCA (hydrodynamic loads) or as-built conditions.

In the letter of January 27, 1986, the applicants committed to complete the qualification of all safety-related active pumps and valves before fuel load.

(d) The applicants have not been able to provide qualification test data for Velan valves 12GM32SB and 6GM62FB and Fisher valve 18BM32. The staff believes that other safety-related equipment may also be qualified by analysis only. To resolve this concern, the applicants shall be required to submit the following information for staff review before fuel load:

- Identify all safety-related NSSS and BOP valves that have been qualified by analysis only.

- Justify the method of qualification.

- Submit evidence that the qualification of all safety-related NSSS and BOP valves can be linked to test data. In the absence of qualification test data, provide additional means of operability assurance. Evidence of qualification by testing can be submitted in the form of actual test reports for prototype equipment or similarity analyses that reference existing test data. A copy of the test reports being cited by the applicants should be included for staff review.

3.10.1.4 Summary

On the basis of the results of (1) the component walkdown and the review of the qualification document packages, (2) the additional explanations and information provided by the applicants throughout the audit, (3) the resolution of the SER items, and (4) the resolution of the operability issues contained in Section 3.10.1.3, the staff can conclude that an appropriate pump and valve operability assurance program has been defined and implemented. The continuous implementation of this overall program should provide adequate assurance that all pumps and valves important to safety will perform their safety-related functions as required for the life of the plant. On successful completion of the requirements delineated in Section 3.10.1.3, the staff concludes that the applicants have qualified those pumps and valves important to safety so as to meet the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50 as well as Appendix B to 10 CFR 50.

3.10.2 Seismic and Dynamic Qualification of Electrical and Mechanical Equipment

The staff's evaluation of the applicants' program for seismic and dynamic qualification of safety-related electrical and mechanical equipment consists of (1) a determination of the acceptability of the procedures used, standards followed, and the completeness of the program in general and (2) an audit of selected equipment items to develop a basis for the judgment of the completeness and adequacy of the implementation of the entire seismic and dynamic qualification program.

Guidance for the evaluation is provided by SRP Section 3.10 (NUREG-0800), and its ancillary documents, Regulatory Guides (RGs) 1.61, 1.89, 1.92, and 1.100, NUREG-0484, and Institute of Electrical and Electronics Engineers (IEEE) Standards 344-1975 and 323-1974. These documents define acceptable methodologies for the seismic qualification of equipment. Conformance with these criteria is required to satisfy the applicable portions of the GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50, as well as Appendix B to 10 CFR 50 and Appendix A to 10 CFR 100. Evaluation of the program is performed by a Seismic Qualification Review Team (SQRT), which consists of engineers from the NRC and the Idaho National Engineering Laboratory (INEL, EG&G Idaho).

The SQRT has reviewed the equipment dynamic qualification information in FSAR Sections 3.9.2 and 3.10 and made a plant site visit from December 3 through December 6, 1985. The purpose was to determine the extent to which the qualification of equipment, as installed at Shearon Harris Unit 1, meets the criteria described above. A representative sample of safety-related electrical and mechanical equipment, as well as instrumentation, included in both NSSS and BOP scopes, was selected for the audit. Table 3.3 identifies the equipment audited. The plant site visit consisted of field observations of the actual final equipment configuration and its installation. This was followed by a review of the corresponding design specifications and test and/or analysis documents, which the applicants maintain in their central files. Observing the field installation of the equipment is necessary to verify and validate equipment modeling used in the qualification program. In addition to the document reviews and equipment inspections, the applicants presented details of maintenance, startup testing, and inservice inspection.

The audit identified both plant generic and specific concerns relating to the seismic and dynamic qualification program. A summary of the issues and their disposition, if any, is presented in the following sections and in Table 3.3.

3.10.2.1 Generic Items

The generic items were:

(1) During the field observation of the four-bay, two-train solid-state protection system train A (NSSS-3), it appeared that the clearance between this unit and an adjacent one was not adequate. On inquiry, it was further learned that this problem may be associated with many cabinets. However, the applicants indicated that they were aware of the situation and a program was in motion to analyze and correct the situation where required.

    The NRC should be informed when the program is completed.

(2) The life span of the nonmetallic parts has not been evaluated.

    The parts should be evaluated, and NRC should be informed when the evaluation is completed.

(3) In a letter dated October 25, 1984, the applicants notified the NRC staff that the seismic qualification of certain air-operated diaphragm valves may have to be reevaluated pursuant to 10 CFR 50.55(e) and 10 CFR 21. The basic issue is that valve assemblies are specified to have natural frequencies greater than 33 Hz and the analyses of the piping system that the valve assemblies are mounted on are performed assuming the valve assemblies are rigid; however, certain air-operated diaphragm valves were found to have natural frequencies less than 33 Hz, thus leading to possible overstressing of the pipe and/or the valve assemblies.

    The SQRT has noted that the overprediction of the natural frequencies of valve assemblies generally results from the use of rather crude analytical models that do not adequately account for major sources of flexibility such as the junction between the actuator and the valve body.

    At the time of the audit, the SQRT was not made aware of this issue and was unable to examine in detail the analytical models for natural frequency calculation of selected valve assemblies. The applicants should propose a program for reevaluating the seismic qualification of power-operated valve assemblies other than those reported in the applicants' final assessment dated September 30, 1985.

3.10.2.2 Equipment-Specific Items

The qualification review of the control room cabinet (BOP-9) indicates that only the cabinet is qualified. However, the structural adequacy as well as the operability of the internals has not been established.

The qualification of the internals should be completed, and the NRC staff should be informed of the satisfactory completion.

3.10.2.3 Summary and Conclusion

On the basis of the observation of the field installation, review of the qualification documents, and responses provided by the applicants to the SQRT's questions during the audit, the applicants' seismic and dynamic qualification program has been found to be well defined and adequately implemented. On closure of the issues identified in Sections 3.10.2.1 and 3.10.2.2 as well as in Table 3.3, the seismic and dynamic qualification of the safety-related equipment at Shearon Harris Unit 1 meets the applicable portions of GDC 1, 2, 4, 14, and 30; Appendix B to 10 CFR 50; and Appendix A to 10 CFR 100.

Table 3.1 Summary of Pump and Valve Operability Review Team (PVORT) audit for Shearon Harris

Plant ID number	Description	Component function	Findings	Resolutions	Status	Remarks
3CE-V43SAB-1 (BOP)	Auxiliary feed pump suction check valve (TRW Mission 8-in. wafer check)	Valve is normally closed. Valve opens when auxiliary feedwater is supplied by steam-driven feed pump.	--	--	Closed	Specific concerns were resolved during audit.
3CT-V885B-1 (BOP)	Containment spray additive valve (Yarway 2-in. motor-operated globe)	Valve is normally closed. Valve opens to allow borated sodium hydroxide solution to go to the containment spray water. Valve fails as is.	--	--	Closed	Specific concerns were resolved during audit.
3SW-B1SA-1 (BOP)	Emergency service water (ESW) intake screening structure isolation valve (Jamesbury 30-in. motor-operated butterfly)	Valve is normally open to allow flow from auxiliary water reservoir to ESW pump. Valve closes if main reservoir is used as water source. Valve fails as is.	--	--	Closed	Specific concerns were resolved during audit.
3AF-F3SA-1 (BOP)	Auxiliary feedwater (FW) pump discharge flow control valve (Masoneilan 3-in. electrohydraulic globe)	Valve is normally open. Valve closes to isolate steam generator FW header in event of rupture of FW header or main steam header. Valve fails open.	--	--	Closed	Specific concerns were resolved during audit.
PIA-SA (BOP)	Emergency service water pump (Hayward Tyler 30 VSN vertical centrifugal 21,500 gpm)	Pump is normally at standby. Pump starts automatically on loss of offsite power or on safety injection signal. Pump supplies cooling water to equipment required for safe plant shutdown.	--	--	Closed	Specific concerns were resolved during audit.
2MS-V95A (BOP)	Auxiliary feedwater pump turbine steam supply isolation valve (Anchor Darling 6-in. motor-operated flex-wedge gate)	Valve is normally closed. Valve opens for operation of auxiliary FW pump turbine on initiation signal. Valve fails as is.	--	--	Closed	Specific concerns were resolved during audit.
3CC-V165 SA (NSSS)	Component cooling water (CCW) to residual heat removal heat exchanger (RHR HX) isolation valve (Velan 12-in. motor-operated gate)	Valve is normally closed to isolate CCW flow from RHR HX 1. Valve opens after event to pass flow through RHR HX. Valve fails as is.	Note[1]	Note[2]	Closed	Valve was qualified by analysis only. Specific concerns were resolved during audit.

See footnotes at end of table.

Table 3.1 (Continued)

Plant ID number	Description	Component function	Findings	Resolutions	Status	Remarks
2WL-L600SA (NSSS)	Reactor coolant drain tank (RCDT) control valve (Copes-Vulcan 3-in. air-operated globe)	Valve is normally open and controls level in RCDT by diverting water to boron recycle system. Valve closes to isolate the RCDT for its safety function. Valve fails closed.	--	--	Closed	Specific concerns were resolved during audit.
APCC-1C-SAB (NSSS)	Component cooling water pump (Pacific DSK centrifugal 11,000 gpm)	Pump is normally operating. Pump supplies component cooling water to various NSSS heat exchangers.	--	--	Closed	Specific concerns were resolved during audit.
2SI-V579A (NSSS)	Cold leg injection and RHR return line isolation valve (Westinghouse 10-in. motor-operated gate)	Valve is normally open in discharge line from RHR pump downstream of RHR head exchanger for cold leg injection and recirculation. Valve closes for containment isolation and hot leg recirculation. Valve fails as is.	--	--	Closed	Specific concerns were resolved during audit.
--	All pumps and valves important to safety	Operate as required during life of plant under normal and accident conditions.	Note[4,5,6,7]	Note[2]	Open[3]	None

[1](Specific Issue) The applicants did not provide any test data to qualify the valve. The applicants shall provide test data demonstrating the ability of this valve assembly to operate as required under its design load conditions.

[2]At the conclusion of the site audit, the PVORT summarized the specific and generic confirmatory issues, as well as the actions necessary to resolve them before fuel load.

[3]The qualification status will be "closed" on resolution of the specific and generic confirmatory issues.

[4](Generic Issue) At the conclusion of the PVORT audit, it was apparent that a complete list of active valves had not been provided in the FSAR. The applicants shall confirm that all active valves are correctly identified in the FSAR.

[5](Generic Issue) Some preservice tests required to be completed before fuel load have not yet been performed. The applicants shall confirm that all appropriate preservice tests have been completed before fuel load.

[6](Generic Issue) Some pumps and valves important to safety have not been completely qualified and installed. The applicants shall confirm that all pumps and valves important to safety are completely qualified and installed before fuel load. Also, the applicants shall confirm that the original loads used in tests and analyses to qualify pumps and valves important to safety are not exceeded by any new loads (i.e., design load reconciliation).

[7]The qualification of some safety-related valves does not appear to be linked to any test data. The applicants shall (a) identify all safety-related NSSS and BOP valves qualified by analysis only, (b) justify the method of qualification, and (c) submit evidence that all safety-related NSSS and BOP valves can be linked to qualification test data. In the absence of qualification test data, provide additional means of operability assurance.

Note: BOP = balance of plant; NSSS = nuclear steam supply system.

Table 3.2 Status of SER items for pump and valve operability assurance

SER items[1]	Finding/ resolution	Status
All active safety-related valves including valves smaller than 2 in. in size should be included in the pump and valve operability program.	Satisfactory	Closed[2]
Clarification of how aging was incorporated in the qualification process should be in the FSAR. In addition, the applicants should commit to establish a maintenance and surveillance program to maintain equipment in a qualified status throughout life of the plant. The criteria for the maintenance and surveillance program should be in the FSAR.	Satisfactory	Closed[2]
The FSAR should be amended to clearly show the loads and conditions considered in the qualification of safety-related pumps and valves.	Satisfactory	Closed[3]
The extent to which draft standards ANSI/ASME QNPE-1 (N551.1), QNPE-2 (N551.2), QNPE-3 (N551.3), QNPE-4 (N555.4) and issued standard ANSI/ASME B.16.41 are used needs to be clearly stated in the FSAR. The applicants' position with respect to RG 1.148 also must be indicated in the FSAR.	Satisfactory	Closed[3]
The FSAR should be amended to show the extent to which operational testing is being used to meet SRP Section 3.10. The extent to which operational testing is performed at full-flow and temperature conditions should be shown.	Satisfactory	Closed[3]

[1]The items for pump and valve operability assurance were identified in the SER and were supplemented by specific comments discussed at a preaudit meeting on March 21, 1985.

[2]This item was adequately resolved on the basis of information submitted by the applicants in a letter dated May 29, 1984.

[3]This item was adequately resolved on the basis of information reviewed by the staff during the site audit on December 3 to 6, 1985. The applicants committed to close out this item in a manner and time frame that are acceptable to the staff.

Table 3.3 Equipment audited

Number	Equipment	Applicants' ID number	Safety function	Findings	Resolution	Status
NSSS-1	Auxiliary feedwater controller	FK-1AF-20 51A1SA 00329	Provides control function for flow control valve 2051A			Qualified
NSSS-2	3-in. diaphragm valve	2-WL-D650SB1 06742	Provides containment isolation function for liquid waste process piping	Maintenance procedures for replacing the valve nonmetallic diaphragm have not been prepared	The applicants' mechanical equipment qualification program will prepare these procedures	Qualified
NSSS-3	4-bay, 2-train solid-state protection system train A	SSP(A) Input 08789	Provides reactor trip and safeguards actuation	(1) Bolting mismatch between report and field (2) Nearby safeguards test cabinet door hinges loose and not welded as required (3) Inadequacy of clearance from adjacent cabinets (generic)	(1) Resolved (2) Field change notice issued for compliance (3) The applicants responded; the problem is being analyzed and corrected (good program in place--generic)	Qualified
NSSS-4	Process control cabinet	PIC-C13 SA-08500	Controls heating, ventilation, and air conditioning (HVAC) systems for safety-related equipment areas. (Supplied by Westinghouse but being used to perform a BOP function)			Qualified
NSSS-5	Component cooling water (CCW) pump	1A-SA 11733	Supplies cooling water to various NSSS safety-related heat exchangers			Qualified
NSSS-7	Main steam relief valve (MSRV) controller	PK-30B1	Provides control function for one of the MSRVs			Qualified
NSSS-8	ASCO solenoid valve	2RC-0525S-B-1 09209	Used to supply air to a pneumatic operator for a diaphram valve identical to NSSS-2			Qualified

NOTE: NSSS = nuclear steam supply system; BOP = balance of plant.

Table 3.3 (Continued)

Number	Equipment	Applicants' ID number	Safety function	Findings	Resolution	Status
NSSS-10	Residual heat removal (RHR) pump and motor	1A-SA 11730 and 11745	Provides low head safety injection			Qualified
NSSS-11	14-in. motor-operated gate valve	2SI-V574-SB1 06035	Closes RHR suction from refilling water storage tank on initiation of suction from containment sump	(1) Substantiation of extrapolation of results from tested size to field size (2) Substantiation of seismic support adequacy	(1) Provided (2) Provided	Qualified
NSSS-12	7300 printed circuit card NAL 2	FS-1SW 70 50 A1-SA 01632	Provides operator with CCW heat exchanger A high flow alarm indication			Qualified
BOP-1	6900-V switchgear	6900 V Bus 1A SA(1) 08873	Provides emergency 6.9-kV power for Class 1E equipment	(1) Major anomalies in first series of tests. Modified and tested as satisfactory (2) Evaluation of life span of nonmetallic parts	(1) Life span cut from 40 to 20 years (2) To be evaluated (generic)	Qualified
BOP-2	Auxiliary relay cabinet	Aux Rly Cab	Provides signal to safety shutdown panel in case of high radiation condition	No model number tag attached to the cabinet	Quality assurance procedure by which model number tags are tracked discussed and found satisfactory	Qualified
BOP-3	Instrument cabinet	Y21-C1E SF-A+B 10875	Provides structural support for safety-related instruments			Qualified
BOP-4	Containment vacuum relief relay	Rly-137-8 07235	Provides signal to safety shutdown panel in case of high radiation condition			Qualified
BOP-5	Containment cooling flow switch	FS-KV75 71AS 01744	Measures low flow conditions in containment cooling duct			Qualified
BOP-6	Centrifugal fan and motor	E-62(1B-SA) 07757	Provides required ventilation for diesel generator, day tank, and silencer rooms			Qualified

NOTE: NSSS = nuclear steam supply system; BOP = balance of plant.

Table 3.3 (Continued)

Number	Equipment	Applicants' ID number	Safety function	Findings	Resolution	Status
BOP-7	1-1/2-in. three-way valve	3-CX-WBSB-1 04670	Modulates flow for cooling of service air handling unit			Qualified
BOP-8	Main steam power-operated relief valve	2-MS-P19SB-1 09183	Provides pressure control function for main steamlines			Qualified
BOP-9	Control room cabinet	RMC-1 10674	Controls/monitors various area and process radiation	(1) Qualification of internals not yet complete (2) Inadequate clearance (generic)	(1) To be completed (generic) (2) To be completed (generic)	Pending
BOP-10	Emergency screen wash pump and motor	1-ASA-SCWP Motor 08070	Provides washing water for intake structure screens			Qualified
BOP-12	30-in. butterfly valve	3SW-B106SB-1 06261	Isolation	Qualification briefly reviewed only to see that complete qualification package was available		Complete
BOP-2A	Hydra Motor valve operator	3CX-W17SA-1 09519	Operates 2-1/2-in. three-way valve that modulates flow for cooling of service air handling unit			Qualified

NOTE: NSSS = nuclear steam supply system; BOP = balance of plant.

4 REACTOR

4.3 Nuclear Design

4.3.2 Design Description

In the SER, the staff stated that the issue of the peaking factor to be used for the loss-of-coolant-accident (LOCA) calculations remains open until an axial power distribution monitoring system (APDMS) or some alternative system or analysis methodology and result are accepted. If an excore APDMS is to be used, the uncertainties to be used with it must be addressed and approved. Until the issue is settled, the reactor would be limited to about 91% power.

The staff has subsequently reviewed a Westinghouse generic (but specifically applicable to Shearon Harris) topical report, WCAP-10665-P, "Excore Axial Power Monitor" (Rahe, September 18, 1984). The primary purpose of the report, as described below, is to present the analysis of the uncertainty relevant to the use of the excore detector system in determining peak power core densities during operation. The review concludes that the report and the derived uncertainties are acceptable provided that additional operational information and analysis of the uncertainty component associated with the burnup correlation matrix be obtained during first-cycle operation.

WCAP-10665-P discusses aspects of a relatively "new" Westinghouse methodology for online monitoring of core power distributions via a multiple-section excore neutron detector and associated analysis-computing system. This report is an addition to previous discussions of the subject, primarily related to the review of RESAR 414, and a topical report, WCAP-9105, "Axial Power Distribution Monitoring Using Four-Section Ex-Core Detectors," which had been reviewed and approved by the staff in 1978. That review indicated that there were still unreviewed areas for the system primarily related to the assignment of uncertainties to the analyses. This new report is intended to complete the record and, in particular, to present the analysis algorithms and input information, system calibration methodology, and associated uncertainty analysis. The report is generally generic in nature, but it is specifically addressed to the Shearon Harris reactor.

This system is of interest for Shearon Harris principally because of the need, especially in the first cycle, to reduce the effective total (power distribution) peaking factor, F_Q, from the standard analysis value of 2.32 to the 2.11 or less required to meet LOCA limits, and to permit operation above 91% power. Similar problems have been solved for other Westinghouse reactors by using an approved movable incore detector measurement system, the APDMS. Because of the present unavailability of that system, the applicants have elected to use the proposed excore system, the excore axial power monitor (ECAPM). ECAPM is conceptually similar to APDMS, but differs greatly in all details of design, operation, analysis, and uncertainty assignment.

The previous topical report (WCAP-9105) described the four-segment excore neutron detectors, some aspects of the algorithm and calibration process, and some comparisons of experimental output versus incore maps. The present topical report briefly presents the system's internals description (e.g., processor functions) and operation, primarily to present and discuss the system input, calibration, and calculational algorithms, leading in turn to (1) the calculation-limit relationship, (2) the analysis of uncertainty, and (3) Technical Specification description.

The processing system gets dynamic information from (1) a (single) four-axial section excore neutron detector, (2) the highest (of the three, for Shearon Harris) core delta-T signal (for power level), and (3) a control rod bank D position signal. The system is also given processing data, via several periodically updated correlation matrices derived from calibration procedures, to translate the dynamic information into peak core power density as a function of core height, kW/ft(Z), via the calculational algorithms. The algorithms determine the core average axial power distribution from the excore currents and matrices and multiply that by the radial peaking factor (as a function of Z) matrix to determine $F_Q(Z)$ and then by average power density to get kW/ft. The system then compares kW/ft(Z) with Technical Specification limits reduced by the system uncertainty [$=F_Q$ limit x K(Z)/(1 + U)] and then alarms when necessary. The system can present continuous information (via a control room cabinet) on measured $F_Q(Z)$ and margins to limits using a cathode ray tube or a printer.

There are three correlation matrices relating excore flux to incore power distribution information: (1) the primary correlation [M], (2) the correction for rod bank position [N], and (3) the correction for fuel-depletion-related effects [G]. The previous topical report described this processing via a Fourier series representation; the present report discusses a second methodology more easily used for error analysis. There is also a matrix for $F_{xy}(Z)$ as a function of rod bank insertion that is partially measured and partially calculated. It is noted that the F_{xy} values used are "measured," not the Technical Specification limit values. The topical report presents details of the calculation algorithms and their use of the correlation matrices, the functional relationship between the existing "measured-calculated" power distribution and limits, and the calibration process to provide the values for the correlation matrices.

Calibration of the matrices is intended to be done (and is to be indicated in the proposed Technical Specification) during initial (cycle) startup and quarterly for [M], and [N] and monthly for [G] and [F_{xy}] thereafter. The quarterly calibrations are done as part of the normal (required) quarterly incore-excore detector calibration mappings and can use the same rod insertions followed by xenon transient axial offset conditions. The monthly maps are done as part of the normally required checks for F_{xy} and $F_{\Delta H}$.

A primary purpose of the topical report is to present the background and analysis for the ECAPM uncertainty assignment (U in the limit formulation). There are three general areas contributing to uncertainty: (1) uncertainties in incore flux-power distribution maps, (2) instruments uncertainties, and (3) variations related to algorithms and correlation matrices. The report examines each of these areas.

The uncertainties assigned for the use of incore flux maps for determining radial and axial, and thus total, power distributions are the standard Westinghouse uncertainties commonly accepted for the relevant areas of measurement, engineering, and rod bow uncertainty. In addition, a value for the uncertainty from the reduction of the number of axial points used in the ECAPM analyses (24) versus the basic data was derived from appropriate comparisons and is used as a multiplier in the ECAPM algorithm.

Instrumentation uncertainties have been analyzed for the power level delta-T input, the control bank position input, and the excore detector current systems. For the first two, the input is such that either the data are conservative (e.g., high auction delta-T signal) or they are of no significance to the error analysis (e.g., peak values do not occur near control rod tips). Thus an explicit uncertainty is not involved. The uncertainty for the excore signals in the ECAPM system is related to reproducibility of the signals. This has been investigated and a term added to the uncertainty summation.

The correlations matrices [M], [N], and [G] each have associated uncertainties, and these have been investigated by examining (axial, pointwise) deviations of ECAPM-determined core average axial distributions for a number of INCORE measured power distribution (calibration-type data) examples relevant to each of the matrices.

For the [M] and [N] matrices, there are sufficient data to develop a value for uncertainty via standard methods. These have been included in the summation of the uncertainties. For the [G] matrix only, very limited data relevant to burnup are available. These data are inconclusive, although apparently indicative of conservatism in the calculational system and there is no need for a related uncertainty component. Consequently, Westinghouse proposes to accumulate more relevant data by performing weekly (rather than the proposed normal monthly) [G] data gathering during the early operation of Shearon Harris, and altering the [G] uncertainty component, if necessary, after an analysis of that data.

The various mapping, instrument, and correlation components discussed above were evaluated as being statistically independent and have been combined with this as a basis. This combination is the value of U in the ECAPM limit comparison.

The report presents proposed modifications to Technical Specifications to use ECAPM, using an example of F_Q limit = 2.10 and assumed F_{xy} surveillance. The specifications are similar in character to those for APDMS but differ in detail. For example, the complex rules for APDMS operating frequency are unnecessary for the continuously operating ECAPM, and the ECAPM measurement-limit relationship and uncertainty are not explicitly given. Standard Technical Specifications 3.2.1 and 3/4.2.2 are modified slightly to indicate changes related to the ECAPM "turn on" level, and Specification 3/4.2.6 is added for ECAPM operability and calibration. No bases are given for Specification 3/4.2.6.

The general descriptions of the ECAPM functions and related components and the interface with operators, including data entry, are reasonably complete and acceptable. The desc¬iptions of the algorithms used and their interactions are also clear and acceptable, and the use of correlations other than the Fourier series described in the previous topical report for error evaluations is a satisfactory equivalent alternative. This system, with appropriate input data, should be capable of providing suitable representations of axial average and peak power densities and should be able to provide these representations for all relevant operating conditions. It has a distinct advantage over APDMS by offering continuous output and margin to limit information.

The calibration processes are well described and appropriately broken down into data types and corresponding test procedures and intervals, and are conveniently, directly associated with existing required data collection tests and intervals. Both the procedures and (with the exception of the [G] data, discussed below) the intervals appear to be reasonable and are acceptable. These calibration descriptions (all of report Section 3.0), including the discussion in Section 3.3, "Plant Operation With ECAPM," should be directly referenced in the Bases for Technical Specification 3/4.2.6 in a discussion of operability, calibration, and turn on.

The uncertainty analysis, the primary motivation of this report, appears to have examined the appropriate areas, including all aspects of input, algorithm, and parameter use, and the report supplies sufficient background material to put the analysis acceptably within the context of system operations.

The uncertainty components assigned to the standard full-core or quarter-core INCORE flux maps (used to provide incore power distribution values for the correlation matrice and F_{xy}) are standard Westinghouse values for measurement, engineering, and rod bow uncertainties. They are acceptable in this use.

The information and analysis used to determine the effect of the reduction of the number of axial points (24) used in ECAPM from the number of the standard mapping data are sufficient and are conservatively treated, and the use within the ECAPM algorithms is acceptable.

The information, arguments, and analyses presented for the uncertainties attributed to instruments for the dynamic input appear reasonable. There is conservatism in the use of a high auction selection for delta-T power level indication, and the bank position uncertainty over its expected range of variation should not be a significant factor in peak axial power determination. The excore signal reproducibility is not described in great detail, but the values provided are reasonable. The overall instrument contribution to uncertainty is thus acceptable.

The uncertainty introduced by the correlation matrices [M], [N], and [G] requires the examination and comparison of ECAPM predictions (using matrices calibrated using previous INCORE maps) and INCORE maps. Sufficient relevant cases for comparison are needed to provide adequate statistics and characterization. There was a reasonably large amount of data for [M] (the basic correlation) uncertainty analysis, and the results of the axial pointwise comparisons appear conservative and acceptable. There are less data for [N] (the control bank correlation), but they appear to be reasonably sufficient and are treated conservatively in arriving at a resulting uncertainty. The uncertainty appears acceptable.

The information for [G] (the burnup-related correlation) is not adequate, and the single available comparison (which extends over a burnup longer than that in the proposed calibration process) is not sufficiently conclusive to provide an unambiguous uncertainty value compatible with the proposed calibration monthly frequency. Westinghouse has selected an uncertainty value indicated by the conservative nature of the very limited data and also proposes a high frequency (weekly) data accumulation early in the Shearon Harris first cycle to explore this uncertainty and provide a new value if necessary.

On the basis of its review of this uncertainty area, the staff has concluded that a temporary use of the Westinghouse-proposed value for this uncertainty value is acceptable provided that [G] is recalibrated (using quarter core maps) approximately weekly (on a full-power week basis) and that the data accumulated in the course of these measurements also be used to provide a more definitive value for the uncertainty. The staff notes that the power distributions change sufficiently over the course of the entire cycle so that it appears prudent that the exploration should continue over the entire first cycle. The staff would expect this data gathering and analysis process, and possible revision of the assigned uncertainty, to result in a supplement to this topical report at the end of the period. The frequent recalibration (as opposed to just data gathering) could be terminated (reverting to monthly) earlier in the cycle (and perhaps even data gathering reduced) if the accumulated information were sufficient to indicate more reasonable corrections were being made and a likely uncertainty value derived and implemented. The staff would expect an interim report if that were the case. It also notes that further information relative to [N] uncertainty could be accumulated in the cycle and the basis for the value, or a new value, improved. This task could be reported in the supplement. Given this temporary, more restrictive calibration and accumulation of information, the staff concludes that the use of the proposed uncertainty values is acceptable.

The various uncertainty components are reasonably independent, and the Westinghouse processes for combining them appear to be statistically acceptable. The combination process is less conservative than that used in some (older) uncertainty areas, including that commonly applied to the APDMS, but many regulatory uncertainty evaluations and approvals have moved in the direction of such combinations, and the staff has concluded that it is acceptable for ECAPM use. The combination process results in the standard flux map uncertainties tending to dominate the final result (for U), and thus any questions relating to the instrument and correlation uncertainties are somewhat decreased in importance by this process. This helps make it possible to accept the Westinghouse proposal for interim use of a [G] uncertainty which is less than complete.

Changes to Technical Specifications 3.2.1 and 3/4.2.2 are relatively minor but properly indicate the transfer (for a 2.10 F_Q system) to ECAPM above the turn on power level and other related changes, and are acceptable. The new ECAPM Specification 3.2.6 is much less detailed in presenting algorithms and uncertainty values than the corresponding standard APDMS specification, but it is acceptable if a suitable basis is provided. The basis should reference the topical report and should explicitly reference the algorithm equations of Section 2, the calibration process descriptions and plant operation of Section 3, and the resulting uncertainty value, U, of Section 4. If the uncertainty is eventually changed via a report supplement, it too should be referenced. For clarity the phrase "and in use" (or an equivalent) should be added after "operable" in the first line of Specification 3.2.6. The meaning(s) of "limit" in Specification 4.2.6.1 should also be clarified. The frequency of calibration may remain as stated, even though more frequent calibration should be used for Shearon Harris for (part of) the first cycle.

Conclusions

Westinghouse has described the algorithms to be used in the ECAPM system and the input and calibration processes to provide information for the system. For this Westinghouse has developed an uncertainty analysis and results to be used with the system power distribution output--limit algorithm as the primary output of this report. On the basis of its review of this system and in particular the development of the uncertainty, the staff has concluded that the algorithms and calibration processes are acceptable and that the associated uncertainties and final resulting uncertainty are generally satisfactory and acceptable, with the possible exception of the uncertainty component associated with the burnup correlation matrix, which requires more operational information and analysis. This component can be properly derived in first-cycle operation. To accomplish this, more frequent data gathering and recalibration of this component matrix are required throughout the first cycle of Shearon Harris operation or until a documented analysis of earlier results indicates a reasonable value has been developed. Furthermore, a supplement to the topical report covering first-cycle experience with this component should be submitted following cycle completion. Proposed Technical Specification changes and additions relating to ECAPM use are generally satisfactory (with minor changes), but a basis with appropriate reference to algorithms, calibration, and uncertainty should be added. The staff considers this acceptable, and Confirmatory Issue 9 is resolved.

5 REACTOR COOLANT SYSTEM

5.3 Reactor Vessel

5.3.2 Pressure-Temperature Limits

In the SER, the staff indicated that the applicants' pressure-temperature limit curves meet all the requirements of Appendix G, 10 CFR 50, except for the safety margins required for the closure flange region materials. The applicants, by letter dated November 21, 1984, indicated that the reference temperature, RT_{NDT}, for the limiting material in the closure flange region is 0°F. On the basis of this value of RT_{NDT}, the Shearon Harris pressure-temperature limits meet the safety margins required by Appendix G, 10 CFR 50, for the closure region materials. This resolves Confirmatory Issue 11.

5.4 Component and Subsystem Design

5.4.2 Steam Generators

5.4.2.2 Steam Generator Tube Inservice Inspection

In the SER, the staff stated that it expects that modifications will be performed on the Shearon Harris steam generators before startup and that it will address this issue in a supplement to the SER. These modifications were required to rectify a generic problem concerning a potential for tube degradation caused by flow-induced vibration in the preheater section of Westinghouse model D steam generators identified in a non-domestic plant in 1981. The staff's evaluation of the information submitted by the applicants relative to the changes being made to the Shearon Harris D4 steam generators to minimize tube vibration is as follows.

The potential for tube wall degradation due to flow-induced vibration in Westinghouse model D4 and D5 steam generators has been thoroughly evaluated and documented in NUREG-1014, "Safety Evaluation Report Related to the D4/D5/E Steam Generator Design Modification."

The primary cause of tube vibration in heat exchangers is hydrodynamic excitation caused by secondary fluid flow on the outside of the tubes. In the range of normal steam generator operating conditions, the effects of primary fluid flow inside the tubes and mechanically induced tube vibration are considered negligible.

To evaluate flow-induced tube vibration in the preheater region of the tube bundle, Westinghouse undertook an extensive program using data from operating plants, full- and partial-scale model tests, and analytical tube vibration models. Operating plant data consisted of tube wear data from tubes removed from steam generators, eddy current tests, and tube motion data from accelerometers installed inside selected tubes. Model testing generated tube wear data, flow velocity distributions, tube motion parameters, and flow-induced tube vibration forcing functions. The tube vibration analyses applied the forcing functions to produce tube motion data. The results of these evaluations were consistent with the early operating experience of preheat steam generators.

On the basis of the above extensive model test and analysis program, Westinghouse designed, verified, and implemented a modification to the steam generator to reduce tube vibratory response to preheater inlet flow excitation. Additionally, the magnitude of the flow-forcing function was reduced through implementation of a preheater flow bypass arrangement in the feedwater system. The verification of the performance of the modifications in reducing tube excitation and response was done with input from a full-scale test under simulated conservative flow and tube support conditions.

The above design modifications developed by Westinghouse for the preheater section of model D4 and D5 steam generators provide a substantial reduction in tube vibration. As a result, the potential for tube wear has been reduced to within acceptable levels.

In the model D4 steam generators in Shearon Harris Unit 1, the modifications consist of expanding selected tubes into the baffle plates in the preheater and splitting the feedwater flow through the auxiliary feedwater nozzle. The close support condition, resulting from tube expansion at the supports, significantly changes the response frequency and also the G-delta value (product of the peak-to-peak acceleration and root-mean-square displacement). The G-delta parameter provides a measure of tube wear resulting from vibration. A reduced value of G-delta is indicative of diminished potential for tube wear. The split feedwater flow reduces the mass flow and velocity of the fluid in the preheater section. Both modifications combine to provide a substantial improvement by reducing the potential for tube wear.

The design modifications and their consequences for steam generators and plant performance were reviewed extensively by the NRC staff and an independent panel of experts. In NUREG-1014, the staff concluded that the proposed modification ensures substantial improvement by reducing the potential for tube wear to within acceptable levels. This conclusion was reached after a thorough review of the test models and testing results as well as an evaluation of analytical models and analytical results.

The acceptable degradation of the steam generator tube walls beyond that at which the tube shall be removed from service or the plugging limit is equal to 40%. This is provided in Section 4.4.5.4 of the Technical Specifications. This plugging limit also applies to the expanded regions of the tubes.

In summary, tube vibration has been thoroughly evaluated. Mechanical and primary flow excitation are considered negligible. Secondary-flow excitation has been evaluated. From this evaluation, the staff has concluded that the proposed expansion of selected tubes and splitting the feedwater flow through the auxiliary feedwater nozzle provides a reduction in tube vibration and in the potential for tube wear to within acceptable levels. Any tube wear resulting from the tube vibration would be limited and would progress slowly. This allows use of a periodic tube inservice inspection program for detection and followup of tube wear. This inservice inspection program, in conjunction with tube plugging criteria, provides for safe operation of the model D4 steam generators in Shearon Harris Unit 1. The applicants revised the FSAR in Amendments 17 and 19, which described the transient analysis margins that result from the D4 modifications. The staff is currently evaluating these amendments and will report its findings in a future supplement.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.2 Containment Heat Removal Systems

Containment Sump Design

During an integrated design inspection (IDI), the IDI team identified a deficiency (D2.3-1) concerning the design of the containment recirculation sumps. Two concerns were addressed in the team's report; namely, the water level in the containment following safety injection could result in the sump screens not being fully submerged, and the approach velocity at the sump screen would be significantly greater than 0.2 ft/sec. The report concluded that the Shearon Harris recirculation sump design is not consistent with the guidance of RG 1.82 and does not meet the FSAR commitments. The primary concern with screens that are not submerged is that floating debris may be drawn to the sumps and block the screens, thereby increasing the head loss at the screens and reducing the net positive suction head (NPSH) margin for the emergency core cooling system (ECCS) and containment spray pumps. The concern over the approach velocity is that nonfloating debris may continue to be transported to the screens rather than settling out.

By letter dated October 25, 1985, the applicants submitted a plant-specific analysis, using the methodology developed under Unresolved Safety Issue A-43 and described in NUREG-0897, Revision 1, "Containment Emergency Sump Performance," to show that postaccident debris will not reach the sumps and, therefore, that adequate pump NPSH margins will be maintained. In addition, the applicants revised their previous commitments to RG 1.82 in light of their subsequent plant-specific analysis.

The applicants' analysis of debris generation is based on postulated jet impingement forces acting on insulation following a high energy line break. All insulation types used inside the containment were evaluated. Most of the insulation is reflective metallic insulation, which, when dislodged, would sink. Fiberglass insulation is only used on the steam generator reference legs; none of the jet cones for the break locations under consideration encompass the fiberglass insulation. MIN-K insulation is used on the pressurizer loop seal piping and selected pipe whip restraints; on the basis of the results of tests, MIN-K insulation will sink when wet. Ricorad and Microtherm insulation is used on portions of the reactor vessel inside the primary shield wall and will be confined to the reactor cavity. From the above considerations, the staff concludes that no floating insulation would be transported to the sump region to block the sump screens.

The reflective metallic insulation and MIN-K insulation will sink but can be transported if the water velocity is greater than 0.2 ft/sec. The applicants presented additional analysis to justify that insulation debris would not reach the sump screens. The analysis was based on the sump design and containment building layout. The sumps are protected by an 18-in.-high curb around the structures. To transport insulation debris to the sump screens, the water must pass through 18-in. x 18-in. drain openings or 3-ft.-wide door openings in the personnel shield wall, traverse a relatively open area where flow velocities would be reduced, and then be transported over the 18-in. curb to reach the screens. The flow velocity just before the 18-in. curb was calculated to be 0.1 ft/sec, which is less than that required to transport reflective metallic insulation, MIN-K insulation, or fibrous insulation debris. Therefore, it is not likely that insulation debris would be transported beyond the 18-in. curb.

On the basis of its evaluation of the applicants' analysis, the staff concludes that insulation debris (floating or nonfloating) would not reach the sump screens following a LOCA as the water level in the containment rises above the 18-in. curb. Therefore, containment recirculation sump performance should not be degraded following high energy line breaks and the NPSH margin of the ECCS and containment spray pumps should not be adversely affected. Therefore, the staff finds the Shearon Harris containment sump design acceptable.

6.3 Emergency Core Cooling System

6.3.5 Performance Evaluation

6.3.5.1 Large-Break LOCA

Certain automatic safety injection (SI) signals are blocked to preclude unwanted SI actuations during normal startup and shutdown conditions. The SI manual block features are provided for low pressurizer and low steamline pressure signals. During plant shutdown SI actuation is blocked at a reactor system pressure of 1900 psia; the accumulator isolation valves are closed and their power removed at 1000 psia. During plant startup, these features are unblocked at approximately the same setpoints. Failure to unblock these systems could seriously impair the reactor safety. The staff has requested the applicants to describe the emergency core cooling system (ECCS) design adequacy during the startup and shutdown conditions.

In Amendments 14 and 23 to the FSAR, the applicants stated that, in the event of a steamline rupture while low pressurizer and low steamline pressure SI actuation signals are blocked, steamline isolation will occur on high negative steam pressure rate. An alarm for steamline isolation will alert the operator to the accident. No core uncovery is expected in this event. For a large-break loss-of-coolant accident (LOCA), sufficient mass and energy would be released to the containment to automatically initiate SI at high containment pressure, a signal that is not blocked. Additionally, multiple indications such as rapid decrease of reactor coolant system pressure, increase in containment pressure, ECCS valve and pump position indication, loss of pressurizer level, status lights, and annunciators are available to the operator at the control board.

Small-break LOCAs are adequately addressed by the applicants and were reviewed and approved by the staff in SER Section 6.3.5.2. The staff concludes that the applicants have demonstrated the adequacy of the ECCS design during the startup and shutdown modes of operation. This resolves Confirmatory Issue 14.

7 INSTRUMENTATION AND CONTROLS

7.2 Reactor Trip System

7.2.2 Specific Findings

7.2.2.4 Design Modification for Automatic Reactor Trip Using Shunt Coil Trip Attachment

During a site audit conducted on January 28-30, 1986, the NRC staff reviewed the drawings and verified that the reactor protection system shunt trip modification has been installed in accordance with the requirements of Generic Letter 83-28. This resolves Confirmatory Issue 15.

7.3 Engineered Safety Features Systems

7.3.3 Evaluation Findings

7.3.3.11 Solid-State Logic Protection System

In the SER, the staff stated that the proposed modification on the solid-state logic protection system test circuit (CI-16) is acceptable subject to the applicants' submittal of the required FSAR changes. By letter dated September 26, 1985, the applicants submitted a copy of the Westinghouse Field Change Notice No. CQLM-10593, which provided the solid-state logic protection system modification to the output relay test panel. The applicants stated that the modification has been incorporated into the plant design as documented by Field Change Request No. I-886. FSAR Section 7.3.3 does not need to modified because this level of detail is not included in the FSAR.

The staff has reviewed the submittal and agrees that the documentation for this item is adequate on the docket file. The resolves Confirmatory Issue 16.

7.6 Interlock Systems Important to Safety

7.6.2 Specific Findings

7.6.2.2 RCS Overpressure Protection During Low Temperature Operation

In the SER, the staff stated that the design of the reactor coolant system (RCS) overpressure protection system during low temperature operation is acceptable subject to staff review of updated drawings and FSAR changes. In FSAR Amendment 17, the applicants updated the system description. Redundant auctioneering devices are provided. The lowest temperature setpoint is generated by both auctioneers. One derivation provides a permissive for the opposite train, and one is used in the reference pressure program. FSAR Figure 7.6.1-7 provided a detailed logic diagram. The staff has reviewed the submittal and finds the documentation adequate. This resolves Confirmatory Issue 18.

8 ELECTRIC POWER SYSTEMS

8.3 Onsite Emergency Power System

8.3.1 AC Power System

Physical Independence of Redundant Safety-Related Systems

The applicants had committed to meet the requirements of RG 1.75 as stated in FSAR Section 8.3.1.2.14. Subsequently, the applicants submitted an amendment to the FSAR identifying exceptions to the separation criteria of RG 1.75. The electrical raceway system design was based on the standard separation criteria in Institute of Electrical and Electronics Engineers (IEEE) 384-1974 as endorsed by RG 1.75. The applicants' amendment establishes lesser separation distances where they could not be maintained in accordance with RG 1.75 and justifies these distances on the basis of test, analysis, or installation of suitable barriers. To provide justification for these lesser separation distances, the applicants instituted a test program conducted by Wyle Laboratories. The test program methodology and the test results are documented in Wyle Test Report No. 4787902.

The applicants submitted the test results with associated information on the revised separation criteria dated November 21, 1985. The revised separation distances are derived from Wyle Laboratories test results and are being implemented in the Shearon Harris plant. This supplement focuses on the evaluation of these test results as the basis for the revised separation criteria. Before initiation of the testing phase of the program, the applicants and Wyle Laboratories personnel developed Test Procedure 47879-01, Revision A, which formed the basis of the tests. To perform a test program to verify the adequacy of the raceway separation criteria, Test Procedure 47879-01, Revision A, defined the worst-case electrical failure that could be postulated to occur in a raceway. This worst-case electrical failure was based on the following failure mode assumptions:

(1) A cable in the raceway system experiences a fault current in excess of the cable allowable energy let-through (I^2t) because of the postulated failure of the primary overcurrent protective device.

(2) The fault current level is assumed to be just below the long time trip setpoint of the circuit secondary (upstream) overcurrent protective device so that the fault is not cleared.

(3) The fault current is conservatively maintained at a constant level until conductor open circuits or steady-state conditions are reached.

A fault current magnitude of 180 amperes was used for control cable tests to demonstrate that a worst-case electrical fault does not have the potential to support combustion or have the capability to generate enough heat to adversely affect the operation of these cables. Five tests were performed for control cables for sizes ranging from 2/C 16 American wire gauge (AWG) to 3-1/C 6 AWG. The fault was assumed to occur between the 120-V panel and the load.

A fault current magnitude of 704 amperes was used for power cables up to 2 AWG and 4200 amperes for power cables greater than 4/0 AWG. Six tests were performed to determine which cable when energized with the rated fault current would produce the worst-case electrical fault. The test results showed that Triplex 350 MCM (million circular mils) cable was the worst-case cable because it sustained the fault current longer and produced the most heat. Using this worst-case cable (i.e., Triplex 350 MCM), the following three different configurations of the installed raceway design were tested to demonstrate the acceptability of the Shearon Harris raceway system.

(1) Test Configuration No. 1

This configuration consisted of a twisted pair of 16 AWG target cable separated 6 in. horizontally from a faulted Triplex 350 MCM cable in free air. This configuration represented field installation of free-air cables going from the following:

(a) tray to tray
(b) tray to conduit
(c) conduit to conduit
(d) tray/conduit to equipment

(2) Test Configuration No. 2

This configuration consisted of a free-air cable, a cable in a 1-in. rigid conduit, and a cable in a flexible conduit. The purpose of this configuration was to demonstrate the acceptability of design where a rigid conduit, a flexible conduit, and a cable in free air are separated by less than 1/4 in. from each other for a worst-case electrical fault.

(3) Test Configuration No. 3

This configuration consisted of two vertically separated horizontal cable trays, a horizontally separated vertical cable tray, a free-air cable, and a rigid conduit. The purpose of this configuration was to demonstrate the acceptability of design for the following:

(a) where a horizontal cable tray passes 12 in. from a vertical cable tray

(b) where a 1-in. rigid steel conduit passes 1 in. below and perpendicular to the cable tray

(c) where a 1-in. rigid steel conduit is separated 1 in. horizontally and runs parallel to the cable tray

(d) where a 1-in. rigid steel conduit is separated 1 in. horizontally from and perpendicular to the side rail of the tray

(e) where a free-air cable passes horizontally 12 in. away from and parallel to the faulted cable in the ladder rung tray

Before the beginning of each cable overcurrent (fault) test, baseline tests of target cable were performed. They consisted of insulation resistance measurements and a 1-min high potential test. At the completion of the cable overcurrent test, post-overcurrent tests were performed on each target cable. The post-overcurrent tests consisted of the insulation resistance measurements and a 1-min high potential test. The acceptability of the raceway design was based on the condition that the target cable pass the post-overcurrent tests, as well as show no physical damage as a result of the test.

The Wyle Laboratories program with the above inputs and assumptions for the target cables demonstrated the acceptability of the raceway design for the following minimum separations:

(1) control free-air cable or tray to Class IE raceway or cable with vertical separation distance of 1 in.

(2) low voltage power tray to Class 1E free-air cable, tray, or flexible conduit with horizontal separation of 12 in. and vertical separation of 36 in.

(3) low voltage tray to Class 1E conduit with horizontal separation of 1 in. and vertical separation of 12 in.

(4) low voltage free-air cable to Class IE free-air cable, tray, or flexible conduit with horizontal separation of 6 in. and vertical separation of 36 in.

(5) low voltage free-air cable or tray to Class 1E conduit with horizontal separation of 6 in. and vertical separation of 12 in.

(6) conduit to Class 1E tray or free-air cable with separation of 1 in.

Also, in this test program the following raceway designs were demonstrated to be unacceptable because the target cable either showed physical damage or failed the post-overcurrent tests.

(1) two free-air power cables separated by 6 in. horizontally

(2) a free-air power cable with other power cable in rigid and/or flexible conduit and separated by a distance of 6 in. vertically

(3) a power cable in a 1-in. rigid steel conduit and separated 1 in. vertically from another power cable

The fault currents selected for the test programs encompass the conditions that can result from failures of the overcurrent protective devices on the feeder cables. If the fault current should exceed the assumed values, it will cause either an upstream protective device operation or a rapid cable failure, thereby preventing long-term overheating of cable to ignite fires. The postulated fault current is reasonably adequate on the basis of the design of the overcurrent protection and electric power supplies. The staff has concluded that the test program with the above assumption and input is acceptable and so are the test results.

The staff has reviewed the application of the test results to the raceway separation criteria in Table 1, "Minimum Separation Distances," attached to the letter of November 21, 1985 (Serial: NLS-85-401). On the basis of its review of the applicants' test results, the staff finds the justification for the deviations from the criteria of RG 1.75 and the revised separation criteria acceptable. The staff's conclusion is based on physical separation as it pertains to electrical fires initiated by electrical faults, occurring as a single failure during a design-basis event, and does not pertain to or modify the 10 CFR 50, Appendix R criteria, which address exposure fires.

8.4 Other Electrical Features and Requirements for Safety

8.4.2 Adequacy of Station Electric Distribution System Voltages

8.4.2.3 Position 3--Optimization of Voltage Levels of the Safety-Related Buses

In the SER, the staff stated that the applicants had submitted an analysis to demonstrate that the transformer tap settings have been fully optimized for the Shearon Harris design. The staff reviewed this information and found it insufficient. The applicants were aware of the staff's requirements to resolve this issue and committed to provide the information necessary to resolve the staff's concern. On this basis, the staff concluded that this item was resolved, subject to confirmation of final documentation.

On December 23, 1985, the applicants provided the necessary information. The staff reviewed the results of the computer analysis used to optimize the transformer tap settings. The staff concludes that the operating voltage levels at the safety-related buses have been optimized for the maximum load and minimum load conditions that are expected throughout the anticipated range of voltage variations of the offsite power sources. Therefore, the staff finds the analysis acceptable, and Confirmatory Issue 19 is resolved.

8.4.7 Use of a Load Sequencer With Offsite Power

In the SER, the staff stated that to accept the use of a single sequencer for both offsite and onsite power sources, it would require that the applicants provide the following additional information on the engineered safety feature (ESF) load sequencer design:

(1) a full description of this design feature in the FSAR, including sequencer components, power supplies, test features, and alarms

(2) a reliability study on the sequencer

(3) a detailed analysis to demonstrate that there are no credible sneak circuits or common mode failures in the sequencer design that could render both onsite and offsite power sources unavailable

Subsequently, the applicants, by letters dated June 28, 1984, and September 26, 1985, provided the required information on the above items. The staff's evaluation of this information follows.

The staff was concerned that when complex load sequencer designs, particularly those using microprocessor-based programmable systems, are used for sequencing loads on both offsite and onsite power, they can be a common source of unreliability for both the onsite and offsite power sources. The Shearon Harris load sequencer uses hardwire techniques and employs Class 1E qualified electromechanical relays for sequencing functions. The sequencer does not use solid-state logics. Each large ESF load actuated by the sequencer has a separate sequencer timer, although there is some sharing of sequencer timers for the smaller ESF loads. If the sequencer fails to automatically actuate an ESF load as designed, the operator can manually actuate the loads from the control room.

The sequencer is designed for testing during power operation. This is accomplished through logic that generates simulated loss-of-coolant-accident (LOCA) and/or loss-of-offsite-power (LOOP) signals and injects them into the program determination logic. Component actuation is stopped by blocking relays that are automatically opened on test start and reclosed when the test is ended. If the blocking relays do not reclose when the test is ended, a sequencer trouble alarm is actuated in the control room as well as at the local sequencer panel. Also, a LOOP or LOCA signal overrides the test mode and automatically deenergizes the blocking relays. The sequencer test is initiated manually either from the main control room or at the sequencer panel. In addition, the sequencer is equipped with annunciators and indicating lights to monitor its status and operation. These are available at the sequencer panel and in the main control room.

The above provisions provide adequate assurance that the load sequencers at Shearon Harris will not be a common source of unreliability for both offsite and onsite power and are, therefore, acceptable. This resolves Confirmatory Issue 20.

9 AUXILIARY SYSTEMS

9.5 Other Auxiliary Systems

9.5.1 Fire Protection

In Supplement No. 2, staff review of the plant alternate shutdown capability was identified as an open item; all other fire protection issues had been resolved. By letters dated February 13 and April 4, 1986, the applicants provided additional information on the fire protection program, including a request for approval of several deviations from staff fire protection guidelines. The staff's evaluation of this information is contained below.

9.5.1.1 Fire Protection Program Requirements

Fire Hazards Analysis

In Supplement No. 2, the staff stated that alternate shutdown capability has been provided for the control room and the cable spreading room. In fact, alternate shutdown capability has been provided for the control room and the electrical equipment room. Separate cable spreading rooms have been provided for each division of redundant shutdown-related circuits in accordance with Section C.5.a. of Branch Technical Position (BTP) CMEB 9.5-1.

9.5.1.3 Fire Brigade

During its review of the fire protection program, the staff expressed the concern that the fire brigade, in responding to a fire in an area containing components from one shutdown division, may open a fire door in a wall separating that division from its redundant counterpart. Both shutdown divisions would then be vulnerable to fire damage. The applicants responded that the fire brigade is trained to respond to a fire so that it would not jeopardize adjoining locations of shutdown-related systems. However, if it became necessary to breech a fire barrier separating redundant systems, the brigade would have the necessary equipment, such as a backup fire hose line, to compensate for the opening. The staff finds this acceptable.

The staff also expressed concern over the ability of the fire brigade to safely vent products of combustion after a fire without compromising the integrity of a fire barrier. By letter dated April 4, 1986, the applicants responded to this concern by describing how smoke will be removed from locations that have suffered a fire. Smoke and heat purging for each fire area is described in the prefire plans. For locations not equipped with a heating, ventilation, and air conditioning (HVAC) system, products of combustion will be exhausted directly to the environs in such a manner that redundant safety-related systems will not be jeopardized. For the remaining areas, smoke and hot gases will be purged using the normal ventilation system or a dedicated smoke purge system. In either case fire barriers will not be breached. Should the fire cause the fire dampers to close, these dampers will be locally reopened after the fire to reestablish air flow. Should the effects of a fire be severe enough to damage HVAC ducts, the damaged ductwork would be repaired or removed to establish a flow path. The staff finds this acceptable.

9.5.1.4 General Plant Guidelines

Building Design

In Supplement No. 2, the staff stated that the main and plant services transformers are more than 50 ft from any buildings and are separated by 2-hour-fire-rated walls. In fact, outdoor oil-filled transformers are located more than 50 ft from safety-related buildings and are separated from the turbine building by 2-hour-fire-rated walls. This conforms with Section C.5.a. of BTP CMEB 9.5-1 and is, therefore, acceptable.

In Supplement No. 2, the staff stated that Underwriters Laboratories, Inc. (UL)-listed fire doors had been installed, and, therefore, the protection of doorways in fire-rated walls complied with staff fire protection guidelines. In fact, fire door assemblies that have been tested and approved by any nationally recognized laboratory meet Section C.5.a.(5) of BTP CMEB 9.5-1 and are, therefore, acceptable.

Safe Shutdown Capability

By letter dated February 13, 1986, the applicant identified the following plant locations where redundant shutdown-related systems are not separated and protected against fire damage in accordance with Section C.5.b.(2) of BTP CMEB 9.5.1:

(1) reactor auxiliary building, elevation 261 ft
(2) reactor auxiliary building, elevation 236 ft

The redundant systems are separated by a horizontal distance of at least 16 ft. The locations are protected by fire detection and suppression systems as delineated in the February 13, 1986, letter. If a fire were to occur in any of these locations, it would be detected before significant flame propagation or room temperature rise occurred. The fire brigade would then extinguish the fire, using manual fire fighting equipment. If rapid fire propagation occurred before the arrival of the brigade, one would expect the fire suppression system to actuate and limit fire spread, reduce room temperatures, and protect vulnerable systems. Pending actuation of the fire suppression system, the physical separation of redundant systems is sufficient to provide reasonable assurance that one shutdown division would remain free of fire damage. The staff concludes, therefore, that the existing level of fire protection for the systems identified in the applicants' February 13, 1986, letter is an acceptable deviation from Section C.5.b.(2) of BTP CMEB 9.5-1.

The applicants also identified a deviation in the reactor auxiliary building, elevation 286 ft. Cable 10137B, which provides control to the reactor coolant vent valve, is not protected by a 3-hour fire barrier per Section C.5.b.(2) of BTP CMEB 9.5-1. The staff was concerned that, in the event of a fire, a hot short of this cable might cause the vent valve to spuriously open. However, this scenario could only occur if stray voltage from another power source made direct contact with the cable leads of cable 10137B. Since this cable is in a dedicated conduit which provides sufficient protection from external hot shorts, the staff has concluded that the lack of a 3-hour fire barrier around cable 10137B is an acceptable deviation from Section C.5.b.(2) of BTP CMEB 9.5-1.

In the February 13, 1986, letter, the applicants requested approval of a deviation in the Unit 2 reactor auxiliary building tank area, elevation 236 ft. The applicants subsequently withdrew the request on the basis of additional analyses that indicated that a deviation does not exist.

In Supplement No. 2, the staff approved several deviations in fire area 1-A-BAL, to the extent that the intervening space between redundant shutdown equipment was not free of combustible materials. Although not specifically stated in Supplement No. 2, the existing fire protection, which includes automatic fire detection and suppression systems, provides reasonable assurance that at least one division of cables for the above-referenced equipment will remain free of fire damage. Therefore, staff approval of these deviations applies to the equipment cabling as well as to the equipment itself.

In Supplement No. 2, the staff identified the barriers enclosing each charging pump as 3-hour-fire-rated barriers. In fact, the applicants have only taken credit for 1-hour-fire-rated barriers. However, because the charging pump cubicles and the adjacent areas are protected by automatic fire detection and suppression systems, the staff concludes that the level of fire protection is adequate.

In Supplement No. 2, an emergency service water intake structure was incorrectly identified as fire area 12-I-ESWPM. The correct area designation is 12-I-ESWPA.

In Supplement No. 2, the staff approved a deviation from BTP CMEB 9.5-1 to the extent that it states that fire detectors should be installed in the emergency service water screening structure. The applicants subsequently indicated that approval was requested for the non-fire-rated doors installed in the exterior walls of this structure. However, because these walls are not fire rated, fire doors are not required. Therefore, a deviation from staff guidelines does not exist.

The staff has reviewed the safe shutdown analysis provided by the applicants together with the drawings of the various areas of the plant (CAR-SH-SK-668-S01 through CAR-SH-SK-668-S28) to determine that the Shearon Harris plant can be safely brought to cold shutdown in the event of a fire. The applicants noted that there were seven areas that require alternative or dedicated shutdown as indicated below (these areas are reviewed separately under "Alternative and Dedicated Shutdown").

(1) fire area 12-A-CRC1 (safe shutdown analysis (SSA) area FCACRC)
(2) fire area 12-A-CR (SSA area FCACRM)
(3) fire area 1-A-SWGRB (SSA area FAASGB)*
(4) fire area 1-A-CSRB (SSA area FFACSB)*
(5) fire area 1-A-BAL (SSA area FAABL5)*
(6) fire area 12-A-BAL (SSA area FCABAL)*
(7) fire area 12-A-HVIR (SSA area FCAHVI)

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*Does not require evacuation of control room.

The applicants provided detailed responses relating to safe shutdown in the event of a fire in the plant. Note that these responses only apply to safe shutdown of fires in areas other than those shown above. Safe shutdown is discussed in the areas immediately below.

(1) Reactivity Control

The control rods will be tripped, either manually or automatically, to provide the immediate shutdown margin required to make the reactor subcritical in the event of a fire in any plant area. A solution of boric acid (2000 ppm) will be added to the primary system from the boric acid tank by means of the normal charging path that employs a charging pump in the charging and volume control system to maintain a shutdown margin while the plant is being brought to the cold shutdown condition from hot standby. At least one train in the normal charging path will be available in the event of a fire in any of the areas requiring safe shutdown. The staff finds this acceptable.

(2) Reactor Coolant System (RCS) Inventory Control

While the plant is being brought to cold shutdown from operational conditions, the RCS inventory loss due to leaks and volume reduction caused by shrinkage is made up by the normal charging path from the boric acid tank. Thus, reactivity and inventory control will be maintained by a solution of boric acid from the boric acid tank. The staff finds this acceptable.

(3) Reactor Coolant System Pressure Control

Reactor coolant pressure is maintained by one bank of the pressurizer heaters. The applicants noted, in a response on July 16, 1984, that the power cables for the 2 banks of 24 redundant heaters powered either by emergency diesel generator SA or SB are separated in cable trays at a horizontal distance of 5 ft. Each bank is capable of maintaining RCS pressure. At the containment wall, SA cables are separated from SB cables by a distance greater than 20 ft. In the pressurizer the separation of the two banks is 18 in. The staff finds the use of the pressurizer heaters in maintaining RCS pressure acceptable.

(4) Reactor Heat Removal

In the event of loss of offsite power, the reactor coolant pumps will not operate, but the core will still be cooled by natural convection. The RCS heat will pass to the steam generators by natural circulation where at least two steam generators will be available. The secondary side of the steam generators will be cooled by feedwater from the auxiliary feedwater (AFW) system. At least one AFW pump will be available for this service. Feedwater may be supplied from the condensate storage tank with water available from the emergency service water system as an alternate source. The steam produced will be voided to the atmosphere by operation of the main steam power-operated relief valves (PORVs). The PORV setpoint can be manually adjusted by an operator in the control room to cool the plant down from the hot standby condition to the point at which the residual heat removal (RHR) system (RCS temperature $\leq 350^{\circ}F$) can be used.

The RHR system cools down the RCS by transferring its heat to the component cooling water (CCW) system in the RHR heat exchangers. In turn, the CCW system passes this heat to the emergency service water (ESW) system, which uses the water in the main reservoir or auxiliary reservoir to cool the water in the CCW system. Thus, the RHR system can maintain the RCS in the cold shutdown condition for a period greatly in excess of 30 days. At least one RHR train, one CCW train, and one ESW train will be available in the event of a fire in any of the areas requiring safe shutdown. The staff finds this acceptable.

(5) Supporting Systems

There are heating, ventilation, and air conditioning (HVAC) units or trains in areas containing safety-related equipment for safe shutdown in which the environment must be controlled by safety-related HVAC units to protect the equipment. The HVAC units are either self-contained or are provided with cold water from the safety-related essential services chilled water system (ESCWS).

A single fire may only damage a single HVAC train (where there are redundant HVAC trains) or may damage a redundant set of HVAC trains when an alternate set is available to protect a redundant piece of equipment; for example, air handling unit 12 (AH-12) (trains A and B) (providing cooling for switchgear A and containment fan cooler starter area) may be destroyed in a single fire, but the redundant air handling unit, AH-13 (trains A and B), is available (providing cooling for redundant switchear B and the redundant containment fan cooler starter area).

The applicants were asked whether both ESCWS trains could be damaged or destroyed in a single fire because, in some cases such as AH-12 or AH-13, both ESCWS trains would serve either air handling unit. The applicants stated that the ESCWS piping is composed of schedule 40 carbon steel and will not be damaged in a fire. In the event the three-way valves are damaged, they will either fail in a manner so as to allow either full flow or no flow through the air handling trains in the fire area. In either case, this will not adversely affect the flow to the other air handling units served by the ESCWS. The staff finds this acceptable.

(6) Instrumentation

The instrumentation available for safe shutdown consists of the following indications:

(a) RCS pressure
(b) pressurizer pressure
(c) RCS hot leg temperature
(d) RCS cold leg temperature
(e) steam generator pressure
(f) pressurizer level
(g) steam generator level
(h) condensate storage tank level
(i) boric acid tank level
(j) source range neutron flux channel
(k) flow indication for the following pumps or systems:

- AFW
- CCW
- ESW
- RHR
- charging pump

(1) other indications

- emergency bus voltage
- standby diesel generator power
- diesel generator day tank level
- essential services chilled water pump operation

At least one safety bus will be available in the event of a fire in any one of the areas described above. In that case, at least one channel of instrumentation shown above will be available for use in safely shutting the plant down after a fire. The staff finds this acceptable.

(7) Power

The emergency power system consists of two diesel generators, associated electrical distribution system, Class 1E batteries, battery chargers, and inverters. Either diesel generator is sufficient to provide the necessary power for safely shutting down the plant. The staff finds this acceptable.

In view of the foregoing, the staff concludes that the applicants can effectively bring the plant to cold shutdown within 72 hours from the control room in the event of a fire in any area that does not require alternative or dedicated shutdown. The staff finds the applicants' capability for safe shutdown acceptable.

Alternate or Dedicated Shutdown Capability

In response to Question 410.45, in a letter dated April 5, 1985, the applicants stated that, for areas for which an alternate shutdown capability had been provided and where no fixed fire suppression system was installed, a request for a deviation would be submitted. The staff is evaluating the Harris Fire Protection Program against the guidelines in BTP CMEB 9.5-1, Revision 2, which contains no requirement for a fixed fire suppression system in areas for which an alternate shutdown capability has been provided. Therefore, no deviation exists.

As noted above, in the section entitled "Safe Shutdown Capability," seven fire areas require alternate or dedicated shutdown. Three of the areas, 12-A-CRC1, 12-A-CR, and 12-A-HVIR, require evacuation of the control room and consequent shutdown by means of an auxiliary shutdown panel. Shutdown by this means is designated as "alternate shutdown," which is discussed immediately below. Shutdown for a fire in the other four areas that does not require evacuation of the control room is discussed below in the section entitled "Dedicated Shutdown."

(1) Alternate Shutdown

In the event of a fire in fire areas 12-A-CRC1, 12-A-CR, and 12-A-HVIR, it is hypothesized that the control room must be evacuated and shutdown controlled from the auxiliary control panel (ACP). The staff has reviewed the applicants' plans to bring the plant to cold shutdown in the event of a fire requiring control room evacuation. The results of that review are described below.

(a) Reactivity Control

The reactor is made subcritical before the operator leaves the control room by insertion of the control rods either automatically or manually. The operator then transfers to the ACP for further operations. At the ACP the operator injects a boric acid solution from the boric acid tank into the reactor vessel, as necessary, by means of the B train charging pump and the B train boric acid transfer pump in order to maintain shutdown margin throughout the cooldown process and during cold shutdown. The staff finds this acceptable.

(b) Reactor Coolant System Inventory Control

The volume of water in the reactor coolant will decrease as a result of leakage and as a result of shrinkage. As cooldown progresses, inventory will be maintained in the same manner as reactivity control is maintained, as described in item (a) above. The staff finds this acceptable.

(c) Reactor Pressure Control

Control of reactor pressure is important to prevent boiling and formation of bubbles anywhere in the reactor coolant system. This is done by maintaining a subcooling margin by use of 1 bank of 24 pressure heaters, pressurizer heater backup group B. These receive power from the power train B emergency diesel generator. Overpressure protection is provided at elevated conditions during hot standby by means of the RCS safety valves. When the system is cooled and depressurized and the residual heat removal system is being employed, overpressure protection is provided by the relief valve on the inlet line to the RHR pump. Pressure relief may also be provided while at hot standby or during the cooldown process by a power-operated pressure relief valve (PORV) on the pressurizer. The staff finds this acceptable.

(d) Reactor Heat Removal

The loss of offsite power prevents operation of the reactor coolant pumps and, thus, the reactor coolant moves through the core and to the steam generators (SGs) by natural circulation. The turbine-driven AFW pump is used to feed the two steam generators with water from the condensate storage tank (CST) or from the emergency service water system in the event of unavailability of the CST. The steam generated by this process is passed into the atmosphere by operation of the main steam PORVs.

When the pressure in the RCS has been reduced to about 425 psig and the temperature to about 350°F, train B of the RHR system is employed to bring the RCS to the cold shutdown condition and to maintain the RCS in that condition. Heat passes from the RCS into the component cooling water (CCW) system (train B) via the train B RHR heat exchanger and from the CCW system into the emergency service water (ESW) system (train B) via the CCW heat exchanger. The ESW system uses the water in the auxiliary reservoir for this cooling process. In the event of any problem in unavailability of the auxiliary reservoir, the ESW can then be shifted to use the water in the main reservoir. Either reservoir has the capacity to sustain shutdown for a period easily in excess of a month. The minimum volume of water in the CST (240,000 gal) is sufficient tp keep the plant at hot standby for 12 hours and then to bring the plant to the point at which the RHR system can continue the cooldown process. The staff finds this acceptable.

(e) Process Monitoring

In the April 5, 1985, letter, the applicants provided the following list of instrumentation available at the ACP once the operators leave the control room:

Description	Tag No.	Location
Pressurizer Level	LT 0459.2	ACP
RCS Pressure W.R.	PT 0402.2	ACP
RCS Loop A Hot Leg Temp	TI 0413.2	ACP
RCS Loop B Hot Leg Temp	TI 0423.2	ACP
RCS Loop A Cold Leg Temp	TI 0410.2	ACP
RCS Loop B Cold Leg Temp	TI 0420.2	ACP
Steam Generator A Pressure	PI 0474.2	ACP
Steam Generator B Pressure	PI 0484.2	ACP
Steam Generator A W.R. Level	LI 0477.2	ACP
Steam Generator B W.R. Level	LI 0487.2	ACP
Neutron Flux Monitor	(New) NI 60A2	ACP
Charging Flow	FI 122.2	ACP
RHR HX Flow	FI 605B2	ACP
AFW Turb Pmp Diff Press	PDI-2180.2	ACP
AFW Turb Pmp Speed	SI 2180.2	ACP
Charging Pmp IB-SB	Status Lights	ACP
Charging Pump IC-SAB (SB Train)	Status Lights	ACP
RHR Pump IB-SB	Status Lights	ACP
AFW Turb Steam Inlet VAS	Status Lights	ACP
CCW Pmp IB-SB	Status Lights	ACP
CCW Pmp 1C-(SB)	Status Lights	ACP
ESW Pmp IB-SB	Status Lights	ACP
ESW Pmp IA-SA	Status Lights	ACP
B.A. Transfer Pmp IB-SB	Status Lights	ACP
B.A. Transfer Pmp IA-SA	Status Lights	ACP
CST Level	LI 9010 B2	ACP
Boric Acid TK Level	LI 161.2	ACP

The staff considers the above list acceptable for monitoring reactivity, RCS inventory, RCS pressure, and the other necessary parameters to bring the plant to and maintain it in a cold shutdown condition.

(f) Major Support Functions

The major support functions are shown below, together with the systems used to provide the function:

- AC/DC Power: Power is provided by means of the train B emergency diesel generator.
- Chilled Water: Those safety-related HVAC systems requiring chilled water receive it from the B train of the essential services chilled water system.
- Heating, Ventilation, and Air Conditioning: Safety-related air handling units provide heating, ventilation and air conditioning as necessary to maintain operation of the train B essential functions.

The staff finds the list of available major support functions acceptable.

(g) 72-Hour Requirement

The applicant presented a chart to show that the reactor could be brought to cold shutdown within 72 hours in the following manner:

- The reactor is tripped, either automatically or manually at the start of a fire (t=0).
- The applicants allow 10 min thereafter for the operator to reach the ACP.
- Several systems are used to control plant parameters after an initial time period of 25 min allowed for plant stabilization. These are diesel generator B, the turbine-driven AFW pump, ESW system train B, the pressurizer heaters (backup train B), ESCWS train B, the PORVs on steam generators A and B, and the necessary HVAC systems. One centrifugal charging pump and one boron transfer pump are utilized to maintain the necessary shutdown reactivity margin and to maintain the RCS inventory. The plant is brought to hot standby ($k_{eff} \leq 0.99$, $T_{AV} \leq 350°F$) by these means.
- The RCS is cooled down from the hot standby condition to an approximate temperature of 350°F, utilizing the systems discussed in the preceding item. Steam generated in the steam generators is discharged to the atmosphere via the steam generator PORVs. This process requires about 7 hours. Some time during this cooldown, the valves on the emergency core cooling system accumulators must be closed to prevent their discharge into the RCS when RCS pressure is reduced below 660 psig.

- Once the RCS temperature is equal to or less than 350°F and its pressure is 425 psig or less, one RHR train, one CCW train, and one ESW train are used to cool the RCS. The RCS is brought to a temperature of 200°F in about 32 hours. This temperature indicates that the plant is in the cold shutdown condition. During this cooldown period, the charging pump and boron transfer pump must be used to introduce a solution of boric acid into the RCS in order to prevent a return to criticality, if this has not been done earlier. The staff finds this acceptable.

(h) Communications

There are several communication systems available in the event of a fire. There is a telephone system with a backup power supply from a security motor control center (MCC), once the center is operational. Transfer to the MCC power supply will be provided automatically. A public address system is connected to the telephone system so that instructions can be issued from the main control room (MCR) or auxiliary control room (ACR). This system is powered by an uninterruptible power package with the station battery as a reliable backup power source. There is a radio system with control stations in the MCR, ACR, waste process control room, central alarm station, and secondary alarm station with power from the uninterruptible power supply (UPS).

A sound power system has been installed in the Shearon Harris plant consisting of multiple wiring circuits and jacks. Master panels are located in the MCR, ACR, and waste processing control room. Loss of all power will not affect availability of the sound power system because it requires no power for operation.

The staff concludes that the communication systems provided are acceptable for communication throughout the plant in the event of operation outside the MCR.

(i) Procedures

The applicants have committed to provide plans for fires in all plant areas. These plans will consist of the following:

- general guidance
- a sketch showing location of important equipment
- information for team leader
- a list of vital safe shutdown and available redundant equipment in the main control room (for fires not requiring control room evacuation) or in the auxiliary control room (for fires requiring control room evacuation)
- information to assist operators in restoring to normal plant lineup those fire protection and ventilation systems used in the fire

The staff finds this acceptable.

(j) ACP Access

The applicants control access to the ACP by means of a security card reader that limits access only to those with proper authorization. In addition, transfer of control to the ACP is a two-step process. The first requires the use of controlled keys to "arm" the control panel. Then, the transfer switches are operated at the ACP to complete the transfer of operation to the ACP. The staff finds this acceptable.

(k) Diesel Generator Fuel Supply

The applicants noted that the onsite fuel supply for the diesel generator is sufficient for 7 days of operation. Additional fuel is readily available from sources within 45 miles (Selma, North Carolina) to 200 miles (Spartanburg, South Carolina) from the site with deliveries made routinely under favorable conditions. The diesel generator fuel supply is acceptable.

(l) Number of Operators Required for Safe Shutdown After a Fire

As part of the staff's fire protection inspection, the safe shutdown procedures including control room evacuation and use of the ACP following a control room fire will be walked through. This audit will confirm that two operators are sufficient to accomplish post-fire shutdown from the ACP. This staff considers this item resolved.

(m) Alternative Shutdown Capability Acceptance Testing

The applicants have committed to perform local and remote tests of the alternative shutdown capability as part of the startup testing program necessary to comply with the requirements of RG 1.68, "Initial Test Programs for Water-Cooled Reactor Power Plants." A test summary is provided in FSAR Section 14.2.12.2.20, "Remote Shutdown Test Summary." These tests should verify that equipment operates from the local control station when the transfer or isolation switch is placed in the "local" position and that the equipment cannot be operated from the control room, but can be operated in the control room when the transfer isolation switch is in the "remote" position. Further, these tests should verify that there is no intermediate transfer switch position where equipment may be operated simultaneously at both locations or at neither location. The staff finds the applicant's commitment acceptable.

(n) Technical Specifications

The applicants noted that the systems required for safe shutdown in the event of a fire requiring control room evacuation are covered by Technical Specifications, either directly or indirectly, by means of the operability definition applied to other pieces of equipment or area temperatures. At this time the NRC staff is reviewing the requirements for safe shutdown after a fire to determine the method by which the applicability of Technical Specifications can best be optimized. Therefore, the applicants will be notified as to the need for and applicability of Technical Specifications for safe shutdown after a fire. This delay will not inhibit the licensing of the Shearon Harris plant.

(o) High/Low Pressure Interfaces

The applicants provided a submittal on September 26, 1985, to resolve the problem of potential high/low pressure interface damage in a single fire. The problem involves two valves forming a high/low pressure interface that are electrically controlled where the controls for both valves may be damaged or destroyed in a single fire with the potential for opening both valves. Thus, a pathway may be provided for damaging a low pressure system and for a loss-of-coolant accident. The applicants' solution involves a combination of 20 ft of separation and 3-hour fire barriers in compliance with the requirements of Section C.5.b.2 of BTP CMEB 9.5-1, "Guidelines for Fire Protection of Nuclear Power Plants."

The applicants submitted further information on January 7, 1986, relating to all high/low pressure interfaces. The applicants noted that there are five systems for which this concern exists:

- the reactor coolant vent system
- the letdown system
- the primary sampling system
- the PORV/block valve
- the RHR system (suction-side valves)

The applicants provided tables to show the protection afforded each system.

- Reactor Coolant Vent System--In the case of the reactor coolant vent system, the applicants noted that the pressurizer vent uses 3/4-in. piping, and the reactor head vent contains a flow restrictor. In both cases, the loss of water would be limited to an amount within the capacity of the charging pump, thus maintaining the level in the pressurizer and reactor vessel in the event the valves opened.

- Letdown System--The low pressure (letdown) portion of the chemical and volume control system is designed with relief valves and orifices downstream of the regenerative heat exchanger to prevent overpressurization in the event the valves in the high/low pressure interface were open.

- Primary Sampling System--The primary sampling system is composed of 3/8-in. tubing. The amount of water loss from this system as a result of inadvertent opening of the high/low interface valves is within the capacity of the charging pump.

- PORV/Block Valves--In the case of the PORVs, either the PORV or block valve will remain closed or will fail in the closed position in the event of a fire in any area through which the control or power cables pass with the exception of a fire in the control room area. This is the case because proper separation of the PORV and block valve cables has been provided in other areas in which they are routed. For the control room fire, both valves (PORV and block) may open. In this case, the operators transfer control power for the PORVs and block valves to the ACP by means of transfer switches. This action causes the spurious signal to be eliminated and the PORVs to return to automatic operation; that is, if the reactor coolant system pressure is less than 2200 psia, any open PORV closes; above the pressure, any closed PORV opens to reduce the reactor coolant system pressure. In addition, one of the steps in the procedure for initiating operation at the ACP requires stabilization of the reactor coolant pressure. This would require examination of the condition of the pressurizer PORV/block valve to enable such stabilization.

- Residual Heat Removal (RHR) System--For the suction side of the RHR system, an analysis by the applicants showed that at least one valve would remain closed in the event of a fire in any area through which the control and power cables passed. In the event of a fire in the control room area, the valves remain closed because of the presence of an interlock in another area, which prevents opening of these valves until the primary system pressure is reduced to the point (<430 psig) at which the RHR system can operate without damage.

On the basis of the above, the staff concludes that the applicants have demonstrated adequate protection and capability to deal with spurious opening of high/low pressure interfaces as a result of fire damage to valve control and power cabling. The staff considers this item resolved.

(p) Reactor Coolant Pump (RCP) Seals

A charging pump is available to inject water into the RCP seals. There is also a component cooling pump available to provide water to the thermal barriers in the RCPs. Either method (injection or thermal barrier cooling) will suffice to prevent damage to the RCP seals. The staff finds this acceptable.

(q) Transfer Switches

The staff has identified an electrical isolation deficiency in which fuses in transfer switches might have to be replaced to achieve and maintain a hot shutdown condition. The applicants have stated that such an electrical isolation deficiency does not exist in the Shearon Harris design because the 120-V ac control circuit cables have been isolated with transfer switches and provided with redundant fuses in the motor control circuits. However, redundant fuses are not provided for breaker controls and diesel generator control circuits. This is because only the positive legs of the control circuits are switched at the main control boards. The negative legs in the main control boards are for the indicating lights which run in different cables. The grounding of a positive leg of a 120-V dc circuit coincident with the grounding of one of the negative legs in another is unlikely. The staff finds this justification unacceptable because grounding of a negative leg and positive leg can create a path to blow control fuses. Thus, this does not meet the intent of the fire protection guidelines where hot shutdown must be achieved without changing fuses or making any other repairs in case of a fire in the control room. Therefore, the staff required that the applicants provide redundant fuses for these breaker control circuits and diesel generator control circuits. In a submittal dated October 15, 1985, the applicants agreed to provide the required redundant fuses. The staff finds this commitment acceptable.

(r) High Impedance Faults

The staff's concern regarding the potential for multi-high impedance faults in circuits that would result in the loss of power to safe shutdown equiment is shown in Figure 9.1. Figure 9.1 contains a sketch of a circuit design that could result in the loss of needed power to safe shutdown equipment. As can be seen in this figure, redundant divisions of safe shutdown cables are properly separated in accordance with Appendix R criteria. However, a fire in fire area A could result in loss of division A safe shutdown equipment and cause damage to non-safe-shutdown cables associated with the division B bus. Further, the individual fault current resulting from the fire damage in the non-safe-shutdown cables may not be enough to trip the individual breakers (B_1 and B_2), but the sum of the faults may be sufficient to trip the main breaker, B_3. If this were to occur, the division B bus and the corresponding redundant division B safe shutdown equipment would be lost. The applicants must demonstrate that multi-high impedance faults in ac power circuits resulting from a single fire cannot result in the loss of function of any safety-related system as outlined above.

The applicants stated that, for such a condition to occur, each branch circuit cable would have to fail along its length so as to result in a unique insulation resistance. This unique resistance would produce a leakage current to ground or conductor to conductor which, when added to the conductor load, would result in a current just below the protective device rating. Thus, an improbable combination of temporary leakage currents would have to occur at once to produce a trip of the main breaker. The applicants then committed to add a general note to the post-fire recovery procedures to alert plant personnel to clear nonessential loads from a tripped bus before reclosing the bus feeder breaker, should the bus feeder breaker trip.

The staff finds the applicants' provision of the note to drop the non-essential loads before reclosing a tripped breaker acceptable in that it resolves the problem of a breaker trip because of high impedance faults in the manner suggested.

(s) Associated Circuits

The applicants reported that a comprehensive equipment list had been developed to show primary and support equipment required to effect safe shutdown. The list included equipment whose maloperation could affect the safe shutdown capability. The applicants reported further that a detailed analysis of the control wiring diagrams was performed to establish the list of cables and support equipment for safe plant shutdown. A list of power cables required for safe plant shutdown was also established. These cables were considered in the analysis, as noted below:

- Cables in a Common Enclosure: Associated cables in an enclosure common with shutdown cables are protected by fuses or breakers. A fire cannot be propagated across a fire area boundary by physically associated cables because of penetration fire stops for cable trays and internal fire-rated seals for conduits. The staff finds the applicants' response acceptable.

- Power Source Case--Coordinated Protection: The staff requires that coordinated protection be provided in associated circuits so that failure of part of a cable in a local fire will not adversely affect power to safe shutdown equipment. The applicants have provided protection devices (breakers/fuses) for each associated circuit to isolate fire-induced electrical faults (hot shorts or short to ground) thus preventing tripping of or damage to the power source and loss of power to a component required for safe shutdown. A breaker coordination study will be performed to ensure proper coordination between the load feeder breakers and bus feeder breakers. Furthermore, this breaker coordination will be tested every 18 months to demonstrate that the overall scheme remains within design limits. The above meets the staff guidelines for associated circuits and is, therefore, acceptable.

- Spurious Operation as a Result of Wire-To-Wire or Cable-to-Cable Faults: The staff is concerned with regard to associated cables to equipment whose maloperation caused by a wire-to-wire or cable-to-cable fault could adversely affect a system's safe shutdown capability. The applicants stated that spurious operation due to wire-to-wire hot shorts was considered in the analysis. Further, in their analysis a spurious operation of a component as a result of a wire-to-wire short did not prevent shutdown of the plant.

  Spurious operations due to stray voltages between cables within a common raceway (cable-to-cable faults) resulting from fire-induced damage have been considered a noncredible event by the applicants. One reason for this is that conductor-to-conductor faults are much more likely to occur before cable-to-cable faults, and conductor-to-conductor faults would preclude cable-to-cable faults. To cause spurious operations by two-wire 125-V ac or dc control or power cable, the applicants indicated that two circuits in contiguous cables (one energized, one deenergized) would need to be damaged by the fire and reconnected in proper sequence. This could occur if, for example, the positive energized wire in the one cable were to be exposed (through cable and wire insulation) to the positive unenergized wire in the adjacent cable and were to make contact with each other. This could only occur in the unlikely event that insulation for both cables and both wires was to be removed in the same general area to permit this contact. Much more likely is the possibility for contact between the positive and negative energized wires in one cable or for the energized positive wire to contact the metallic raceway where either contact would cause the circuit breaker to open, thus removing the possibility for spurious operation. On the basis of the above, the staff finds the applicants' response relating to spurious operation of associated circuits as a result of wire-to-wire or cable-to-cable faults acceptable.

(2) Dedicated Shutdown

In the event of a fire in fire areas 1-A-SWGRB, 1-A-CSRB, 1-A-BAL, and 12-A-BAL, the control room does not need to be evacuated. However, a fire in any of these areas requires the use of a non-safety-related dedicated HVAC unit to cool the safety-related process instrumenation cabinet (PIC) room. In these cases, the control room would not be evacuated and safe shutdown would be effected with the equipment and in a manner similar to that described under "Safe Shutdown Capability" once the dedicated HVAC unit is started in an area separate from the areas starred. The staff finds this acceptable for a fire in these areas.

The staff finds the applicants' analysis of fire protection of systems necessary to bring the plant to hot shutdown and then to cold shutdown satisfactory and in compliance with the criteria of Section C.5.c ("Alternate or Dedicated Shutdown Capability").

Electric Cable Construction, Cable Trays, and Cable Penetrations

In the SER, the staff stated that safety-related cable trays located outside the cable spreading rooms are separated from potential fire exposure hazards by 3-hour-fire-rated barriers. In fact, redundant safety-related cable systems located outside the cable spreading room are separated from potential fire exposure hazards in non-safety-related areas by 3-hour fire barriers. They are protected from fire exposure hazards in safety-related areas by a combination of spatial separation, fire barriers, fire detection systems, and fire suppression systems, as stipulated in the applicants' descriptions of the plant fire protection program. On the basis of an evaluation of this information, the staff concludes that the protection of cable systems from the effects of exposure fires conforms with Section C.5.e.(2) of BTP CMEB 9.5-1 and is, therefore, acceptable.

Ventilation

In the SER, the staff stated that charcoal filters are provided with water spray systems in accordance with RG 1.52. In fact, only the engineered safety feature charcoal filters are protected in accordance with RG 1.52. However, automatic sprinkler protection is provided for the areas outside the filter housing as described in the applicants' fire protection program. This conforms with Section C.5.f. of BTP CMEB 9.5-1 and is, therefore, acceptable.

Lighting and Communications

By letter dated February 13, 1986, the applicants requested approval of two deviations from Section C.5.g. of BTP CMEB 9.5-1, to the extent that it stated that 8-hour battery-powered lighting units should be installed in certain locations. The applicants propose to utilize portable lights in locations that must be traversed to perform cold-shutdown-related manual operations. These operations need not commence before 8 hours after onset of a fire, by which time the emergency lighting units' battery power supplies would be spent and normal plant lighting would be restored. The staff concludes that no benefit would be derived by installing 8-hour battery-powered emergency lighting units in these cold shutdown locations. The use of hand lights as a supplement to normal plant lighting in these locations, and in access routes thereto, is, therefore, an acceptable deviation from Section C.5.g. of BTP CMEB 9.5-1.

The applicants also requested approval to rely on the security perimeter lighting in the outdoor area from the power block to the diesel generator building. The security lights are powered from the dedicated security diesel. The applicants stated that the security lighting system provides sufficient illumination for an operator to traverse this area and that any postulated fire capable of requiring an operator to travel to the diesel generator building will not interrupt power from the security diesel. On these bases, the staff concludes that the absence of 8-hour battery-powered emergency lights in the yard area is an acceptable deviation from Section C.5.g of BTP CMEB 9.5-1.

9.5.1.5 Fire Detection and Suppression

In the SER, the staff stated that a fire detection system was provided in all areas containing safety-related equipment and for all areas that present a fire exposure hazard to safety-related equipment. The applicants have since identified locations where areawide fire detection is not provided. These locations have been further evaluated in this supplement and in Supplement No. 2. Except for deviations approved by the staff, the applicants have provided fire detectors in accordance with Section C.6.a of BTP CMEB 9.5-1.

Fire Protection Water Supply System

In the SER, the staff stated that yard hydrants are provided at intervals of 250 ft along the fire protection water supply loop. The hydrants are actually spaced approximately 250 ft apart. The maximum distance between any two hydrants is 285 ft. This meets Section C.6.c of BTP CMEB 9.5-1 and is, therefore, acceptable.

In the SER, the staff also stated that electrical supervision had been provided for all valves in the fire protection water supply system. In fact, only control and sectionalizing valves in the fire water systems are electrically supervised. This is in accordance with Section C.6.c of BTP CMEB 9.5-1 and is, therefore, acceptable.

9.5.1.6 Fire Protection of Specific Plant Areas

Containment

In the SER, the staff stated that automatic sprinkler systems are provided in the electrical cable trays, the electrical penetration areas, and over the charcoal filter housings. In fact, the sprinkler systems are installed over the electrical cable trays in the penetration areas. This correction does not change the staff's evaluation of the fire protection for containment.

Control Room

In the SER, the staff stated that peripheral rooms in the control room complex are separated from the control room by 1-hour-fire-rated barriers. In fact, the peripheral rooms are neither separated by a fire barrier nor protected by an automatic sprinkler system as prescribed in Section C.7.b of BTP CMEB 9.5-1. The staff was concerned that, in the event of a fire in the office/kitchen area, smoke and hot gases would propagate into the main terminal cabinet and control room. By letter dated April 4, 1986, the applicants proposed to install an automatic sprinkler head in the office/kitchen area. The details concerning the installation of this sprinkler are included in the above referenced letter. This modification provides reasonable assurance that the effects of a fire will be confined to the office/kitchen area. The staff considers the proposed protection an acceptable deviation from Section C.7.b of BTP CMEB 9.5-1.

Safety-Related Battery Rooms

In the SER, the staff stated that hose stations and portable fire extinguishers are available in the safety-related battery rooms. In fact, manual fire fighting equipment is positioned outside these rooms. The location of this equipment meets staff fire protection guidelines and is, therefore, acceptable.

9.5.1.7 Summary of Deviations From CMEB 9.5-1

In Supplement No. 2, the staff listed the previously approved deviations from staff fire protection guidelines. The staff incorrectly identified one deviation (No. 7) as pertaining to the switchgear room. In fact, the approved deviation was for the cable spreading room, relative to the guidelines for 1-hour barriers, sprinklers, and detectors.

On the basis of its evaluation of the applicants' February 13 and April 4, 1986, letters, the staff has concluded that the following deviations are also acceptable:

(1) fire protection for redundant shutdown systems as described in Section 9.5.1.4

(2) lack of 8-hour battery-powered lighting units in certain plant locations as described in Section 9.5.1.4

(3) fire protection for the control room peripheral areas as described in Section 9.5.1.6

9.5.1.8 Conclusion

On the basis of the above review, with the approved deviation, the staff concludes that the fire protection program conforms to GDC 3 and BTP CMEB 9.5-1 and is, therefore, acceptable.

9.5.3 Lighting Systems

The staff found the emergency lighting system at Shearon Harris acceptable subject to confirmation that specific operating procedures were in effect. By letter dated September 26, 1985 (Serial: NLS-85-231), the applicants provided additional information about the Shearon Harris plant design with regard to this one emergency lighting issue.

The Shearon Harris design does not provide for emergency lighting powered from a Class 1E source any place in the plant except the control room. The staff's concern, as stated in the SER, is the lighting would not be available in safety-related areas following certain design-basis events. This, in turn, would preclude any manual actions in these areas to mitigate the consequences of the event. In the above letter, the applicants responded by stating that all necessary actions to achieve and maintain safe shutdown could be accomplished from the control room without the necessity of sending anyone outside the control room. The staff found this acceptable provided procedures covering such a shutdown were developed and implemented.

In the above letter, the applicants stated that such procedures are covered in the emergency operating procedures (EOPs), which are based on the Westinghouse Owners Group Emergency Response Guidelines, Revision 1. The applicants stated that the plant can be safely shut down and maintained in a safe shutdown condition for more than 7 days for the control room using only safety-related equipment, assuming a design-basis seismic event coincident with loss of offsite power (LOOP). The fact that the scope of the Shearon Harris EOPs covers actions outside the control room when possible does not alter the staff's evaluation.

Lighting for the alternate shutdown panel is provided from both the normal ac and emergency ac systems. Power for the normal ac system is from a non-Class 1E source without ac backup. The emergency ac system is powered from non-Class 1E distribution panels connected to the Class 1E safety buses through appropriate isolation devices. These safety buses are powered from the onsite emergency diesel generators in the event of a LOOP. Illumination for access between the control room and alternate shutdown panel is provided by the normal ac lighting system or the emergency dc lighting system (non-Class 1E). In the event of a loss of control room habitability coincident with a LOOP, the emergency dc lighting will activate automatically to provide illumination for access to the alternate shutdown panel. After approximately 10 sec, the emergency ac lighting system will be automatically energized and provide adequate lighting at the alternate shutdown panel. The emergency ac lighting will be available for an indefinite period. The staff finds this acceptable, and Confirmatory Issue 23 is resolved.

9.5.4 Emergency Diesel Engine Fuel Oil Storage and Transfer System

In the SER, the staff stated:

> FSAR Section 9.5.4 does not contain specific information on pressure differential alarms on duplex fuel oil filters, but the applicant has indicated that pressure differential alarms are provides. The staff finds this acceptable, subject to confirmation that details of these alarms are included in the FSAR.

In subsequent discussions, it was determined that the above differential pressure alarms are discussed in FSAR Section 8.3 as part of the diesel generator instrumentation. FSAR Section 8.3.1.1.2.14 describes the duplex fuel oil filter differential pressure alarms as being an input to the common diesel generator trouble alarm. The pressure sampling points for these alarms are shown on FSAR Figure 9.4.2. The staff finds this acceptable, and Confirmatory Issue 22 is resolved.

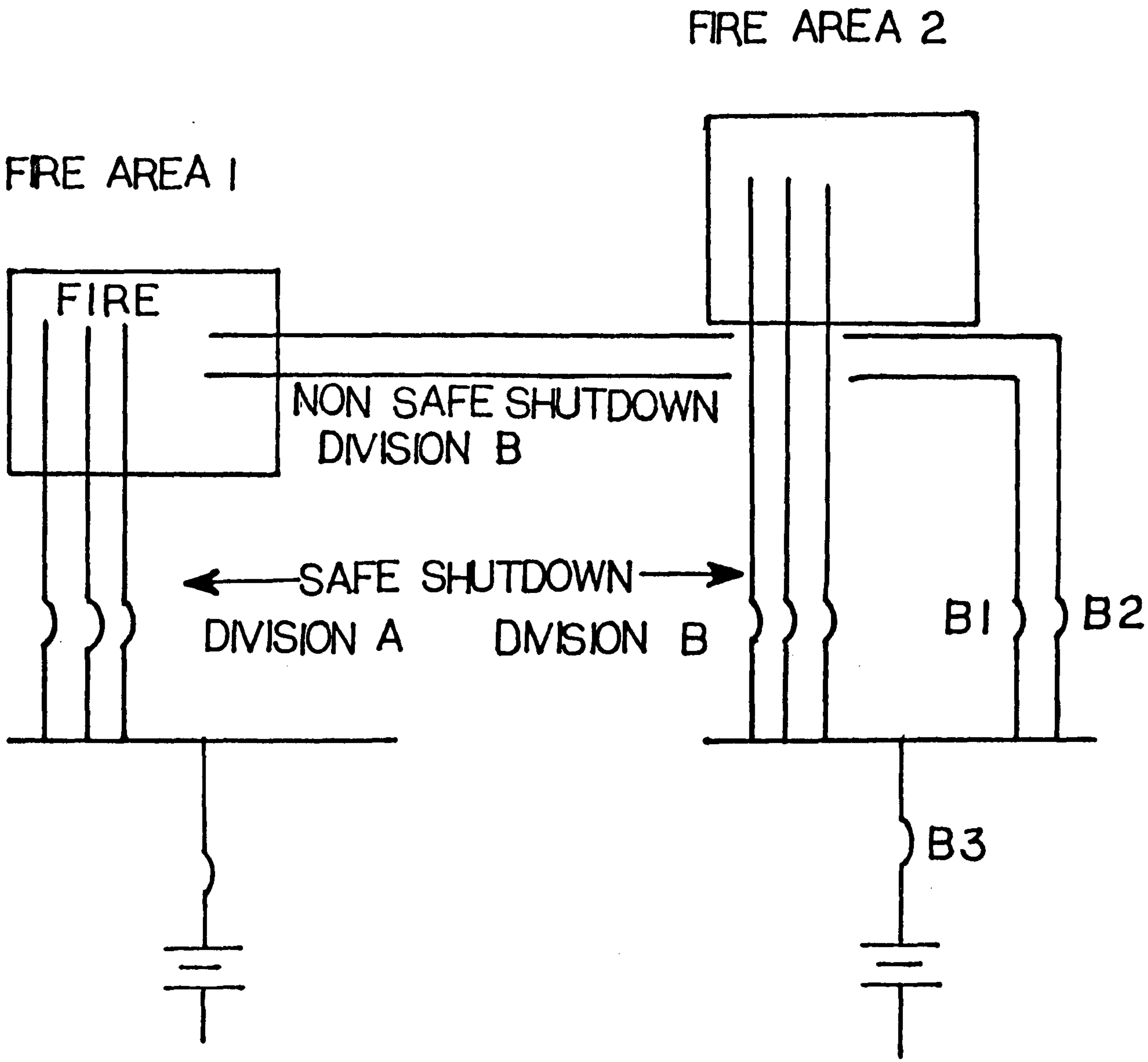

Figure 9.1 Circuit design wherein resultant faults could result in loss of needed power

11 RADIOACTIVE WASTE MANAGEMENT

11.4 Solid Waste Management

When the SER was issued, the applicants had not submitted their process control program (PCP). Subsequently, by letter dated September 4, 1985, the applicants submitted the solid waste PCP for staff review. The staff has reviewed this document and finds the PCP meets the intent for a PCP as defined in the guidelines for radiological effluent technical specifications (RETS), and thus the PCP is acceptable to start processing solid waste. An important consideration in the staff approval of the PCP is that a quality assurance program sufficient to ensure that all provisions of the PCP are met is required to be established by the applicants and, where subcontracted services are provided, that measures are taken to ensure vendors are capable of supplying services to the quality specified in procurement documents.

Although the PCP conforms to the RETS guidance on the subject, a number of issues have been identified recently with respect to PCPs, and the staff is currently in the process of evaluating these issues to determine whether they warrant implementation on all operating power reactors. The staff has prepared a draft document entitled "Guidelines for Preparation of a Solid Waste Process Control Program." This document notes several areas for potential improvement of the PCP. Any changes in previous requirements will be subject to backfit considerations.

Although the staff cannot require changes in the current Shearon Harris PCP, without appropriate backfit considerations, the applicants might wish to consider the staff draft document and, in particular, the following items:

(1) The plant's quality assurance could be enhanced by requiring additional tests for the vendor's production-level product to verify that the characteristics of the solid product are similar to the acceptable prequalification product test results. The solidification vendor's topical report, approved by the NRC, only demonstrates the vendor's system is capable of producing a solid product. Prequalification is required to demonstrate the system produces a product that meets the criteria of 10 CFR 61. Because waste products may be unacceptable if the system is operated outside its qualified parameters, verification that the system is in control could be accomplished by a production-level sample and evaluation test. The staff is pursuing this on a generic basis. Resolution of this generic issue may require the applicants to adopt a practice of production-level sampling.

(2) Sections 5.2.3.4, "Test Solidification," and 5.2.3.5, "Test Solidification Acceptability": The subject section for the applicants' PCP states that test solidification will be considered acceptable if it is shown to be free standing with less than 0.5% by volume free liquid. These criteria are consistent with those listed in a previous version of the Standard Technical Specifications. The acceptance criteria applied to the solidified test specimen are being reviewed by the staff on a generic basis.

The staff is also considering the generic requirement that an additional test, similar to a prequalification test, where submersion of the test specimen into water for 2 weeks followed by a compression test (per American Society for Testing and Materials (ASTM) C39 or ASTM-D 1074, whichever applies) should be required, since there are questions about whether the product might crumble when a load is applied or the product is exposed to water. The acceptance criterion would be that the compression test strength be similar to the prequalification test data for the acceptable solidified product. Passing of this test would lend a degree of confidence that the other test criteria (such as leachability, biodegradation, and radiation resistance) could be met without testing for the same. The testing technique is also being considered on a generic basis, and the resolution of the generic issue may require the applicants to adopt this practice. The staff considers Confirmatory Item 28 resolved.

11.5 Process and Effluent Radiological Monitoring and Sampling Systems

In Section 11.5.2 of the SER, the staff stated that it had not completed its review of the applicants' proposed method for determining release of radioactivity from the safety/relief valves and the atmospheric dump valves.

In a letter dated September 26, 1985, the applicants provided additional information on the procedure for estimating noble gas activity releases via the secondary steam pressure relief and safety valves. The activity releases are estimated by measuring the steamline activity during normal, transient, and accident conditions, converting it to concentration, and then multiplying it by the steam mass flow as determined by assuming each valve passes its design flow rate when it opens. The staff has reviewed this procedure and found it acceptable. The Technical Specifications for this monitor are provided in Technical Specification Tables 3.3-10 and 4.3-7 under Item 19, "Main Steam Line Radiation Monitors," and are also acceptable. Accordingly, Open Item 10 is closed.

13 CONDUCT OF OPERATIONS

13.3 Emergency Planning

13.3.1 Introduction

The staff's evaluation of the Shearon Harris Emergency Plan dated March 1983 (and Revision 1 dated September 1983) was presented in the SER. Evaluations of Revisions 2 and 3 of the plan were reported in SER Supplement Nos. 1 and 2, respectively. This supplement reports on the staff's finding regarding offsite emergency medical services and the Shearon Harris public information brochure. Also included is Federal Emergency Management Agency's (FEMA's) finding on the adequacy of the offsite radiological emergency plans and preparedness and an evaluation of the full-participation exercise. The staff's overall conclusion regarding the overall state of onsite and offsite emergency preparedness is also presented.

13.3.2 Evaluation of the Emergency Plan

13.3.2.8 Emergency Facilities and Equipment

In the SER, the staff stated:

> The ERF's were evaluated as interim facilities in accordance with applicable portions of 10 CFR 50 and NUREG-0654 and found to be adequate. The applicant stated in a letter dated April 15, 1983, in response to Generic Letter 82-33, that the final facilities will be completed before fuel load, and then will be evaluated in accordance with Supplement 1 to NUREG-0737.

Supplement 1 to NUREG-0737 (issued via Generic Letter 82-33) indicates that the NRC staff will conduct postimplementation reviews of the final emergency response facilities (ERFs) and provides all licensees and applicants with the requirements and guidance against which the ERFs will be evaluated. The staff will conduct a postimplementation appraisal of the Shearon Harris ERFs in accordance with the provisions of Supplement 1 to NUREG-0737 on a schedule to be developed between the applicants and the NRC staff.

On the basis of information in the applicants' emergency plan and procedures, the findings of the onsite emergency plan implementation appraisal, and observations made during the May 17, 1985, exercise, the staff finds that, on an interim basis, the Shearon Harris ERFs are adequate to support a response effort in the event of an emergency. The staff considers this matter resolved from the standpoint of issuing an operating license.

13.3.2.12 Medical and Public Health Support

Offsite Emergency Medical Services

In a recent decision, GUARD v. NRC, 753 F.2d 1144 (D.C. Cir. 1985), the U.S. Court of Appeals vacated the Commission's interpretation of 10 CFR 50.47(b)(12) to the extent that a list of facilities was found to constitute adequate arrangements for medical services for members of the offsite public exposed to dangerous levels of radiation. The Commission has now provided guidance to be followed in determining compliance with this regulation pending its determination of how it will proceed in response to the Court's remand. In particular, the Commission directed that licensing boards, and the staff in uncontested cases, should consider the uncertainty attendant on the Commission's interpretation of this regulation, especially in regard to its interpretation of the term "contaminated injured individuals." In GUARD, the Court left open to the Commission the discretion to reconsider whether that term should include members of the offsite public exposed to dangerous levels of radiation, thus, whether arrangements for this population of individuals are required at all. For this reason, the Commission observed that it may be reasonably concluded that "no additional actions should be taken now on the strength of the present interpretation of that term." Accordingly, the Commission observed that it can be found "that any deficiency which may be found in complying with a finalized post GUARD planning standard (b)(12) is insignificant for the purposes of 10 CFR §50.47(c)(1)." In this regard, the Commission, as a generic matter, noted the low probability of accidents that might result in exposure of members of the offsite public to dangerous levels of radiation as well as the slow development of adverse reactions to overexposure. See "Emergency Planning; Statement of Policy," 50 FR 20892.

Consistent with the foregoing Statement of Policy, the applicants have, by letter dated December 11, 1985, confirmed that the emergency plans of the involved offsite response jurisdictions contain a list of medical service facilities. The existence of such a list in the pertinent plans has also been confirmed by FEMA. Further, the applicants have committed to fully comply with the Commission's response to the Court's remand.

Accordingly, on the basis of the factors identified by the Commission in its Statement of Policy, the staff has determined that the requirements of 10 CFR 50.47(c)(1) have been satisfied so as to warrant issuance of the operating license pending further action by the Commission with respect to the requirements of 10 CFR 50.47(b)(12).

13.3.3 Federal Emergency Management Agency (FEMA) Finding on Offsite Plans and Preparedness

In a memorandum dated August 7, 1985, from R. W. Krimm, FEMA provided its interim findings on offsite radiological emergency response plans and preparedness for Shearon Harris. The FEMA Region IV Regional Assistance Committee (RAC) completed a review of the North Carolina Emergency Response Plan, Revision 1, dated September 3, 1984, including the four local plans for Chatham, Harnett, Wake, and Lee Counties with changes through April 1985. FEMA Region IV staff included the exercise evaluation report dated June 28, 1985, for the May 17-18, 1985, exercise, in its evaluation of the state of offsite emergency preparedness. On the basis of its review, FEMA finds that the State and local emergency plans are adequate and capable of being implemented, and the exercise demonstrated that offsite preparedness is adequate to provide reasonable assurance that appropriate measures can be taken to protect the health and safety of the public living in the vicinity of the Shearon Harris station in the event of a radiological emergency.

Public Information Brochure

The FEMA Region IV RAC and FEMA Region IV staff have reviewed the Emergency Preparedness Public Information Brochure prepared by Carolina Power and Light Company for Shearon Harris. FEMA finds that the brochure meets the criteria of NUREG-0654/FEMA-REP-1, Revision 1. The NRC staff concurs in the FEMA finding.

13.3.4 Conclusion

On the basis of the staff's review of the applicants' radiological emergency plan, the evaluation of the full-participation exercise, and a review of FEMA's finding of State and local emergency plans and preparedness, the staff concludes that the state of onsite and offsite emergency preparedness at Shearon Harris provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency.

13.3.5 TMI Action Plan Items

III.A.1.2 Upgrade Emergency Support Facilities

In Section 7.5.2.2 of the SER, the staff stated that its evaluation of the applicants' conformance to the guidelines of RG 1.97, Revision 2, would be included in the evaluation of the designs of the emergency support facilities.

Generic Letter 82-33 requested licensees and applicants to provide a report to the NRC staff describing how the postaccident monitoring instrumentation meets the guidelines of RG 1.97 as applied to emergency response facilities. The applicants responded to the generic letter on April 15, 1983. Response specific to RG 1.97 was provided on September 6, 1983. Additional information was provided by letter dated June 3, 1985.

A detailed review and technical evaluation of the applicants' submittals was performed by EG&G Idaho, Inc., under contract to the NRC, with general supervision by the NRC staff. This work is reported by EG&G in the technical evaluation report (TER), "Conformance to Regulatory Guide 1.97, Shearon Harris Nuclear Power Plant, Unit Nos. 1 and 2," dated September 1985 (see Appendix H). The staff has reviewed this report and concurs with the conclusion that the applicants either conform to or are justified in deviating from RG 1.97 for each postaccident monitoring variable except accumulator tank level and pressure.

Subsequent to the issuance of the generic letter, the NRC staff held regional meetings in February and March 1983 to answer licensee and applicant questions and concerns regarding the NRC policy on RG 1.97. At these meetings, it was noted that the NRC review would only address exceptions taken to the guidance of RG 1.97. Furthermore, where licensees or applicants explicitly state that instrument systems conform to the provisions of the regulatory guide, it was noted that no further staff review would be necessary. Therefore, the review performed and reported by EG&G only addresses exceptions to the guidance of RG 1.97. This supplement addresses the applicants' submittals based on the review policy described in the NRC regional meetings and the conclusions of the review as reported by EG&G.

The staff has reviewed the evaluation by EG&G (see Appendix H) and concurs with its bases and findings. The applicants either conform to or have provided an acceptable justification for deviations from the guidance of RG 1.97 for each postaccident monitoring variable except accumulator tank level and pressure. RG 1.97 recommends that instrumentation be provided to monitor the accumulator tank level and pressure. The applicants have provided this instrumentation, which conforms to the criteria for Type D, Category 2 variables with the exception of environmental qualification. The applicants stated that the accumulators are a passive system and action takes place within 1 min of the accident or well after safety injection depending on the leak size. In either case operator action is not required to mitigate the consequences of the postulated accident. Also, the signals from the accumulator tank level and pressure instrumentation are not used as inputs to any automatic safety function. Although the staff agrees with the applicants that this is a passive system and the variables are not used for automatic initiation of a safety function, it believes that this instrumentation should be provided to permit the operator to determine if the plant safety functions (accumulator discharge) are being performed. In this regard, the staff finds the applicants' proposed exception to the guidelines of RG 1.97 unacceptable.

Conclusion

On the basis of the staff's review of the TER and the applicants' submittals, the staff finds that the Shearon Harris design is acceptable except as noted below with respect to conformance to RG 1.97, Revision 2.

The staff recognizes that the operator can infer from either level or pressure that the accumulator has injected borated water into the reactor coolant system. Therefore, it is the staff's position that the applicants designate either level or pressure as the key variable to determine accumulator discharge and provide instrumentation for that variable that meets the requirements of 10 CFR 50.49. If accumulator level is selected as the key variable, the range should be expanded to meet the regulatory guide recommendations. It is also the staff's position that the applicants shall install and have operational qualified accumulator tank level or pressure instrumentation at the first scheduled outage of sufficient duration, but no later than startup following the first refueling outage. However, by letter dated February 6, 1986, the applicants stated that they considered the above design change a plant-specific backfit pursuant to 10 CFR 50.109. The NRC staff is currently evaluating the information in this letter to determine whether it will change the staff's conclusions discussed above.

13.5 Plant Procedures

13.5.1 Administrative Procedures

In the SER, the staff stated that the administrative procedures related to the following TMI Action Plan Items are of particular interest to NRC:

- I.A.1.2 Shift Supervisor Administrative Duties
- I.C.2 Shift and Relief Turnover Procedures
- I.C.3 Shift Supervisor Responsibilities
- I.C.4 Control Room Access

* I.C.5 Procedures for Feedback of Operating Experience to Plant Staff
* I.C.6 Verification of Correct Performance of Operating Activities

When the SER was issued, these procedures had not yet been completed by the applicants. Subsequently, the NRC Region II staff evaluated Items I.C.2, I.C.3, I.C.4, and I.C.5 and found them acceptable as reported in Office of Inspection and Enforcement (IE) Reports 50-400/85-16 and 50-400/86-16, dated June 5, 1985 and April 14, 1986. The following paragraphs closing out these items have been excerpted from the above-cited IE reports:

> <u>Item I.C.2, "Shift and Relief Turnover Procedures"</u>: FSAR TMI Appendix, page 10; FSAR Section 13.5.1.3; SER Section 13.5.1; and CP&L Operations Procedures OMM-022 address CP&L's compliance with this action item. The inspector evaluated Procedures OMM-001 and OMM-002 and found them to be an acceptable method of assuring that operating shifts are properly relieved. This item is closed.
>
> <u>Item I.C.3, "Shift Supervisor Responsibilities"</u>: FSAR TMI Appendix, page 11; FSAR Section 13.1.2; SER Section 13.5.1; Harris Plant Technical Specification, Section 6.1.2; and Operations Procedure OMM-001 clearly establish the command duties of the shift supervisor and emphasize the primary management responsibility for safe operation of the plant. The inspector evaluated Procedure OMM-001 and found it to clearly define the duties, responsibilities, and authority of the shift supervisor (shift foreman) and the control room operators. Harris Plant Technical Specifications, Section 6.1.2, addresses a management directive signed by the Vice-President, Harris Nuclear Project, to be issued yearly to all plant personnel. The directive is required to state that the shift foreman is responsible for the safe operation of the plant. This item is closed.
>
> <u>Item I.C.4, "Control Room Access"</u>: The CP&L procedure which controls access to the control room, Procedure OMM-001, Section 5.1.11, was reviewed and found to be acceptable. The inspectors have evaluated the implementation of the procedure, during various tours of the control room, and noted no significant problems. In each instance the inspectors have bound these controls to be acceptable. This item is closed.
>
> <u>Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff"</u>: FSAR TMI Appendix, page 13; FSAR Section 13.5.1; SER Section 13.5.1; CP&L Quality Assurance Procedure CQAD 80-1; [and] Operations Procedures ONSI-1 and D-AP-31 describe the guidance required to ascertain that operating experience is fed back to the plant's staff. The inspector evaluated the applicable site procedures (ONSI-1, O-AP-31, and Enclosure 1 to CQAD 80-1) and found them to address adequately the concerns identified in TMI Action Item I.C.5. This item is closed.

The staff will report its findings on the two remaining open items in a future supplement.

15 ACCIDENT ANALYSES

15.4 Reactivity and Power Distribution Anomalies

15.4.3 Rod Cluster Control Assembly Malfunction

In the SER, the staff indicated that a potential controller problem exists for the dropped control rod event that could lead to the imposition of operating restrictions. It also indicated that it was anticipated that a detailed analysis would show that if the transient should occur, the thermal limits would not be exceeded, but that this analysis had not as yet been submitted for Shearon Harris Unit 1. The staff also indicated that Westinghouse has developed a solution for the problem via a new methodology for analyzing the event and has documented it in a topical report (WCAP-10297P) and that this report and its methodology have been evaluated by the staff and approved (memorandum from L. Rubenstein, March 2, 1983). The solution requires a reactor- and cycle-specific analysis showing that departure from nucleate boiling (DNB) limits will not be exceeded. The Shearon Harris Unit 1 FSAR has been revised in Amendment 21 to include a discussion of this analysis, and the results for Cycle 1 operation indicate that DNB limits will be met for this cycle. Thus, operating limits will not be necessary for Cycle 1. Each future reload cycle will require a similar cycle-specific analysis as part of the normal reload analysis. This is no longer a license condition.

15.8 Anticipated Transients Without Scram

An anticipated transient without scram (ATWS) is an expected operational transient (such as a loss of feedwater, loss of condenser vacuum, or loss of off-site power to the reactor) that is accompanied by a failure of the reactor trip system to shut the reactor down (as required).

On June 26, 1984, the Commission amended the regulations to add the ATWS rule, 10 CFR 50.62, "Requirements for Reduction in Risk From Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants." 10 CFR 50.62 requires that each Westinghouse pressurized-water reactor (PWR) must have equipment from sensor output to final actuation device, which is diverse from the reactor trip system, to automatically initiate the auxiliary feedwater system and initiate a turbine trip under conditions indicative of an ATWS. This equipment must be designed to perform its function in a reliable manner and be independent (from sensor output to the final actuation device) from the existing reactor trip system. In accordance with 10 CFR 50.62(d), the applicants have submitted a schedule for implementation of the requirements of the ATWS rule. The ATWS implementation for Shearon Harris is scheduled (letter dated October 14, 1985, from A. B. Cutter to H. R. Denton) for completion before startup following the first refueling outage with acceptance testing and training completed within the following 3 months. This is in conformance with the ATWS rule, and, therefore, the staff finds this schedule acceptable.

The staff has not completed its review of the Shearon Harris design for compliance with the ATWS rule; however, staff review and approval is not a requirement for plant licensing. The staff is currently reviewing PWR generic ATWS designs and will review the Shearon Harris plant-specific design in accordance with the plant-specific review schedule. The final acceptability of the ATWS mitigation system will be predicated on the staff review of the design against the requirements set forth in the published rule (10 CFR 50.62) on this subject. The results of this review will be reported in a supplement to this SER in accordance with the schedular requirements set forth in 10 CFR 50.62(d).

Generic Letter 83-28

On February 25, 1983, both of the scram circuit breakers at Unit 1 of the Salem Nuclear Power Plant failed to open on an automatic reactor trip signal from the reactor protection system. This incident occurred during the plant startup, and the reactor was tripped manually by the operator about 30 sec after the initiation of the automatic trip signal. The failure of the circuit breakers has been determined to be related to the sticking of the undervoltage trip attachment. Before this incident, on February 22, 1983, at Unit 1 of the Salem Nuclear Power Plant, an automatic trip signal was generated based on steam generator low-low level during plant startup. In this case, the reactor was tripped manually by the operator almost coincidentally with the automatic trip. Following these incidents, on February 28, 1983, the NRC Executive Director for Operations (EDO) directed the staff to investigate and report on the generic implications of these occurrences at Unit 1 of the Salem Nuclear Power Plant. The results of the staff's inquiry into the generic implications of the incidents at the Salem unit are reported in NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant." As a result of this investigation, the Commission requested (by Generic Letter 83-28, dated July 8, 1983) that all licensees of operating reactors, applicants for an operating license, and holders of construction permits respond to certain generic concerns. These concerns are categorized into four areas: (1) Post-Trip Review, (2) Equipment Classification and Vendor Interface, (3) Post-Maintenance Testing, and (4) Reactor Trip System Reliability Improvements.

(1) Post-Trip Review

The first action item, Post-Trip Review, consists of Action Item 1.1, "Program Description and Procedure" and Action Item 1.2, "Data and Information Capability." This supplement to the Shearon Harris SER (Supplement No. 3) addresses both action items.

Action Item 1.1: Program Description and Procedure

The following review guidelines, developed after initial evaluation of the various utility responses to Item 1.1 of Generic Letter 83-28, incorporate the best features of those submittals. As such, these review guidelines in effect represent a "good practices" approach to post-trip review. The NRC staff reviewed the applicants' response to Item 1.1 against the following guidelines:

A. The licensee or applicant should have systematic safety assessment procedures established that will ensure that the following restart criteria are met before restart is authorized.

- The post-trip review team has determined the root cause and sequence of events resulting in the plant trip.

- Near-term corrective actions have been taken to remedy the cause of the trip.

- The post-trip review team has performed an analysis and determined that the major safety systems responded to the event within specified limits of the primary system parameters.

- The post-trip review has not resulted in the discovery of a potential safety concern (e.g., the root cause of the event occurs with a frequency significantly larger than expected).

- If any of the above restart criteria are not met, then an independent assessment of the event is performed by the Plant Operations Review Committee (PORC), or another designated group with similar authority and experience.

B. The responsibilities and authorities of the personnel who will perform the review and analysis should be well defined.

- The post-trip review team leader should be a member of plant management at the shift supervisor level or above and should hold or should have held an SRO (senior reactor operator) license on the plant. The team leader should be charged with overall responsibility for directing the post-trip review, including data gathering and data assessment, and the leader should have the necessary authority to obtain all personnel and data needed for the post-trip review.

- A second person on the review team should be an STA (shift technical advisor) or should hold a relevant engineering degree including special transient analysis training.

- The team leader and the STA (engineer) should be responsible to concur on a decision/recommendation to restart the plant. A nonconcurrence from either of these persons should be sufficient to prevent restart until the trip has been reviewed by the PORC or by an equivalent organization.

C. The licensee or applicant should indicate that the plant response to the trip event will be evaluated and a determination will be made about whether the plant response was within acceptable limits. The evaluation should include:

- A verification of the proper operation of plant systems and equipment by comparison of the pertinent data obtained during the post-trip review to the applicable data provided in the FSAR (Final Safety Analysis Report).

- An analysis of the sequence of events to verify the proper functioning of safety-related and other important equipment. Where possible, comparisons with previous similar events should be made.

D. The licensee or applicant should have procedures to ensure that all physical evidence necessary for an independent assessment is preserved.

E. Each licensee or applicant should provide in its submittal, copies of the plant procedures which contain the information required in Items A through D. As a minimum, these should include the following:

   - The criteria for determining the acceptability of restart.

   - The qualifications, responsibilities, and authorities of key personnel involved in the post-trip review process.

   - The methods and criteria for determining whether the plant variables and system responses were within the limits as described in the FSAR.

   - The criteria for determining the need for an independent review.

By letter dated November 7, 1983, the applicants provided information regarding the Shearon Harris post-trip review program and procedures. The NRC staff evaluated the applicants' program and procedures against the review guidelines for Item 1.1 developed as described above. A brief description of the applicants' response and the staff's evaluation of the response against each of the review guidelines is provided below:

A. The applicants have established the criteria for determining the acceptability of restart. On the basis of its review, the staff finds that the applicants' criteria conform to the guidelines as described for Item 1.1 in Review Guideline A above, and, therefore, are acceptable.

B. The qualifications, responsibilities, and authorities of the personnel who will perform the review and analysis have been clearly described. The staff reviewed the applicants' chain of command for responsibility for post-trip review and evaluation and finds it acceptable.

C. The applicants have described the methods and criteria for comparing the event information with known or expected plant behavior. On the basis of its review, the staff finds them acceptable.

D. The applicants have established criteria for determining the need for independent assessment of an event. On the basis of its review, the staff finds them acceptable. In addition, the applicants have established procedures to ensure that all physical evidence necessary for an independent assessment is preserved. The staff finds that this action to be taken by the applicants conforms with the guidelines as described for Item 1.1 in Review Guidelines A and D above.

E. The applicants have provided for staff review a systematic safety assessment program to assess unscheduled reactor trips. On the basis of its review, the staff finds this program acceptable.

On the basis of staff review, the applicants' Post-Trip Review Program and Procedures for Shearon Harris Unit 1 are acceptable.

Action Item 1.2: Data and Information Capability

The following review guidelines were developed after initial evaluation of the various utility responses to Item 1.2 of Generic Letter 83-28 and incorporate the best features of these submittals. As such, these review guidelines in effect represent a "good practices" approach to post-trip review. The NRC staff reviewed the applicants' response to Item 1.2 against these guidelines:

A. The equipment that provides the digital sequence of events (SOE) record and the analog time history records of an unscheduled shutdown should provide a reliable source of the necessary information to be used in the post-trip review. Each plant variable which is necessary to determine the cause and progression of the events following a plant trip should be monitored by at least one recorder (such as an SOE recorder or a plant process computer) for digital parameters, as well as by strip charts, a plant process computer, or an analog recorder for analog (time history) variables. Performance characteristics guidelines for SOE and time history recorders are as follows:

   - Each SOE recorder should be capable of detecting and recording the sequence of events with a sufficient time discrimination capability to ensure that the time responses associated with each monitored safety-related system can be ascertained, and that a determination can be made about whether the time response is within acceptable limits based on FSAR Chapter 15, "Accident Analyses." The recommended guideline for the SOE time discrimination is approximately 100 msec. If current SOE recorders do not have this time discrimination capability, the applicants should show that the current time discrimination capability is sufficient for an adequate reconstruction of the course of the reactor trip and post-trip events. As a minimum, this should include the ability to adequately reconstruct the transient and accident scenarios presented in Chapter 15 of the plant FSAR.

   - Each analog time history data recorder should have a sample interval small enough so that the incident can be accurately reconstructed following a reactor trip. As a minimum, the applicants should be able to reconstruct the course of the transient and accident sequences evaluated in the accident analysis of Chapter 15 of the plant FSAR. The recommended guideline for the sample interval is 10 sec. If the time history equipment does not meet this guideline, the applicants should show that the time history capability is sufficient to accurately reconstruct the transient and accident sequences presented in FSAR Chapter 15. To support the post-trip analysis of the cause of the trip and the proper functioning of involved safety-related equipment, each analog time history data recorder should be capable of updating and retaining information from approximately 5 min before the trip until at least 10 min after the trip.

- All equipment used to record SOE and time history information should be powered from a reliable and noninterruptible power source. The power source used need not be safety related.

B. The SOE and time history recording equipment should monitor sufficient digital and analog parameters, respectively, to ensure that the course of the reactor trip and post-trip events can be reconstructed. The parameters monitored should provide sufficient information to determine the root cause of the unscheduled shutdown, the progression of the reactor trip, and the response of the plant parameters and protection and safety systems to the unscheduled shutdowns. Specifically, all input parameters associated with reactor trips, safety injections, and other safety-related systems, as well as output parameters sufficient to record the proper functioning of these systems, should be recorded for use in the post-trip review. The parameters deemed necessary, as a minimum, to perform a post-trip review that would determine if the plant remained within its safety limit design envelope are presented in Table 15.1. These parameters were selected on the basis of staff engineering judgment following a complete evaluation of utility submittals. If the applicants' SOE recorders and time history recorders do not monitor all of the parameters suggested in this table, the applicants should show that the existing set of monitored parameters is sufficient to establish that the plant remained within the design envelope for the accident conditions analyzed in FSAR Chapter 15.

C. The information gathered by the SOE and time history recorders should be stored in a manner that will allow for data retrieval and analysis. The data may be retained in either hard copy (e.g., computer printout, strip chart record), or in an accessible memory (e.g., magnetic disc or tape). This information should be presented in a readable and meaningful format, taking into consideration good human factors practices such as those outlined in NUREG-0700.

D. Retention of data from all unscheduled shutdowns provides a valuable reference source for the determination of the acceptability of the plant vital parameter and equipment response to subsequent unscheduled shutdowns. Information gathered during the post-trip review is to be retained for the life of the plant for post-trip review comparisons of subsequent events.

By letter dated November 7, 1983, the applicants provided information regarding their post-trip review program data and information capabilities for Shearon Harris. The staff evaluated the applicants' submittal against the review guidelines described above. The applicants' deviations from these guidelines were reviewed with the applicants by telephone on January 14, 1986. A brief description of the applicants' responses and the staff's evaluation of the responses against each of the review guidelines is provided below:

A. The applicants have described the performance characteristics of the equipment used to record the SOE and time history data needed for post-trip review. On the basis of its review, the staff finds that the SOE and time history recorder characteristics conform to the review guidelines for Item 1.2 and are acceptable.

B. The applicants have established and identified the parameters to be monitored and recorded for post-trip review. On the basis of its review, the staff finds that the parameters selected by the applicants include all of those identified in Table 15.1 and conform to Review Guideline B of Item 1.2 and, therefore, are acceptable.

C. The applicants described the means for storing and retrieving the information gathered by the SOE and time history recorders, and for presenting this information for post-trip review and analysis. On the basis of its review, the staff finds that this information will be presented in a readable and meaningful format and that the storage, retrieval, and presentation conform to Review Guideline C of Item 1.2.

D. The applicants' submittal of November 7, 1983, indicates that the data and information used during post-trip reviews will be retained in an accessible manner for the life of the plant. On the basis of this information, the staff finds that the applicants' program for data retention conforms to Review Guideline D of Item 1.2 and is acceptable.

On the basis of its review of the applicants' submittal and the staff's telephone conversation with the applicants, the staff concludes that the applicants' post-trip review data and information capabilities for Shearon Harris are acceptable.

(3) <u>Post-Maintenance Testing</u>

The third action item, Post-Maintenance Testing, includes Action Items 3.1.3, "Identify Post-Maintenance Test Requirements in Existing Technical Specifications Which Degrade Safety," and 3.2.3, "Identify Post-Maintenance Test Requirements in Existing Technical Specifications." The requirements for these two items are identical except that Item 3.1.3 applies these requirements to the reactor trip system components and Item 3.2.3 applies them to all other safety-related components. Because of this similarity, the responses to both items were evaluated together.

<u>Action Items 3.1.3 and 3.2.3: Reactor Trip System Components and All Other Safety-Related Components</u>

Licensees and applicants shall identify, if applicable, any postmaintenance testing requirements in existing Technical Specifications which can be demonstrated to degrade rather than enhance safety. Appropriate changes to these test requirements, with supporting justification, shall be submitted for staff approval.

The applicants for Shearon Harris Unit 1 responded to these requirements with submittals dated November 7, 1983, and May 31, 1985. The applicants stated in these submittals that there were no postmaintenance testing requirements in Technical Specifications for either reactor trip system or other safety-related components which degraded safety.

The appended contractor's report (Appendix I to this SER supplement) finds the applicants' responses to Generic Letter 83-28, Items 3.1.3 and 3.2.3, acceptable. The staff concurs with the contractor's findings and finds the applicants' responses for these items acceptable. These items are closed by this action.

On the basis of (a) the applicants' statement that no postmaintenance testing requirements were found in Technical Specifications that degraded safety and

(b) the contractor's report (EG&G Idaho, Inc., NTA-7099) appended to this supplement, the staff finds the applicants' responses acceptable for Items 3.1.3 and 3.2.3 of Generic Letter 83-28.

(4) Reactor Trip System Reliability Improvements

The fourth action item, Reactor Trip System Reliability Improvements includes Action Item 4.3, "Reactor Trip Breaker Automatic Shunt Trip."

Action Item 4.3: Reactor Trip Breaker Automatic Shunt Trip

Action Item 4.3 of Generic Letter 83-28 requires that modifications be made to improve the reliability of the reactor trip system by implementation of an automatic actuation of the shunt trip attachment on the reactor trip breakers. By letters dated November 18, 1983, and June 10, 1985, the applicants provided responses to the plant-specific questions identified by the staff in its safety evaluation report of the generic Westinghouse design (Eisenhut, 1983). The staff has reviewed the applicants' proposed design for the automatic actuation of the reactor trip breaker shunt trip attachments and finds it acceptable.

The applicants have not specified the implementation date for these modifications. Implementation should be accomplished before licensing.

The following plant-specific items were identified on the basis of the staff's review of the Westinghouse Owners Group (WOG) proposed generic design for this modification:

A. Provide the electrical schematic/elementary diagrams for the reactor trip and bypass breakers showing the undervoltage and shunt coil actuation circuits as well as the breaker control (e.g., closing) circuits, and circuits providing breaker status information/alarms to the control room.

The applicants provided the electrical schematic diagrams for the reactor trip and bypass breakers showing the undervoltage and the shunt trip circuits. The design of the electrical circuits has been reviewed and found to be consistent with the WOG generic proposed design, which was previously reviewed and approved by the staff. The staff finds this is acceptable.

B. Identify the power sources for the shunt trip coils. Verify that they are Class 1E and that all components providing power to the shunt trip circuitry are Class 1E and that any faults within non-Class 1E circuitry will not degrade the shunt trip function. Describe the annunciation/indication provided in the control room on loss of power to the shunt trip circuits. Also describe the overvoltage protection and/or alarms provided to prevent or alert the operator(s) to an overvoltage condition that could affect both the undervoltage coil and the parallel shunt trip actuation relay.

Redundant Class 1E power sources are used for the shunt trip actuation of the reactor trip breakers and for the shunt trip of the bypass breakers. Class 1E circuitry is separated from non-Class 1E circuitry. Therefore, a fault within non-Class 1E circuitry will not degrade the shunt trip function. This design conforms to the guidance of RG 1.75 and is, therefore, acceptable.

The breaker position status lights are used to supervise the availability of power to the shunt trip circuits. The red light connected in series with the shunt coil and the "a" auxiliary contact indicates that the breaker is closed. It also indicates that the power is available to the shunt trip device and, therefore, provides detectability of power failure to the shunt trip coil. Normally the shunt trip coils in the reactor trip breakers are in the deenergized state. When the trip breakers are closed, the red lamp current (approximately 50 ma) flows through the trip coil to monitor the circuit continuity, but the current is not large enough to actuate the trip coil armature. Since the current through the shunt trip coils is interrupted when the breaker trips, energization of the shunt trip coil is only momentary. The maximum available voltage occurs during a battery equalizing charge at a maximum voltage of 115% of the nominal voltage. Because of the short-duty cycle of the shunt trip coil, it can operate at this overvoltage condition without harmful effects.

The added shunt trip circuitry is powered from the reactor protection logic voltage supply (48 V dc). Components in the added shunt trip circuitry have been selected on the basis of their ability to perform their intended functions up to 115% of nominal voltage. The reactor protection logic voltage is regulated with overvoltage protection set at 115% of nominal voltage.

On the basis of its review, the staff concludes that appropriate consideration has been given to the aspects of the design described above and the design is, therefore, acceptable.

C. Verify that the relays added for the automatic shunt trip function are within the capacity of their associated power supplies and that the relay contacts are adequately sized to accomplish the shunt trip function. If the added relays are other than the Potter and Brumfield MDR series relays (P/N 2383A38 or P/N 955655) recommended by Westinghouse, provide a description of the relays and their design specifications.

The added relays for the automatic trip function are Potter and Brumfield MDR series relays (P/N 955655). Westinghouse has verified that the relay contacts are adequately sized for the shunt trip function and are within the capacity of their associated power supplies. The staff finds that this aspect of the design is acceptable.

D. State whether the test procedure/sequence used to independently verify operability of the undervoltage and shunt trip devices in response to an automatic reactor trip signal is identical to the test procedure proposed by the WOG. Identify any differences between the WOG test procedure and the test procedure to be used and provide the rationale/justification for these differences.

The applicants have committed to implement the test procedure proposed by the WOG. The test procedure provides for the independent confirmation of the operability of the undervoltage trip and shunt trip devices. The staff finds this commitment acceptable.

E. Verify that the circuitry used to implement the automatic shunt trip function is Class 1E (safety related) and that the procurement, installation, operation, testing, and maintenance of this circuitry will be in accordance with the quality assurance criteria in Appendix B to 10 CFR 50.

The applicants confirmed that the circuitry used to implement the automatic shunt trip function is Class 1E (safety related) and that the procurement, installation, operation, testing, and maintenance of this circuitry will be in accordance with the quality assurance criteria in Appendix B to 10 CFR 50. The staff finds this is acceptable.

F. Verify that the shunt trip attachments and associated circuitry are/will be seismically qualified (i.e., be demonstrated to be operable during and after a seismic event) in accordance with the provisions of RG 1.100, Revision 1, which endorses IEEE Standard 344, and that all non-safety-related circuitry/components in physical proximity to or associated with the automatic shunt trip function will not degrade this function during or after a seismic event.

The applicants state that the shunt trip attachment and associated circuitry will be seismically qualified in accordance with RG 1.100, Revision 1, and that all non-safety-related components will not degrade the function of the shunt trip attachment during or after a seismic event. The staff finds this is acceptable.

G. Verify that the components used to accomplish the automatic shunt trip function are designed for the environment where they are located.

The applicants note that the components used to accomplish the automatic shunt trip function are designed for the environment where they are located. The staff finds this is acceptable.

H. Describe the physical separation provided between the circuits used to manually initiate the shunt trip attachments of the redundant reactor trip breakers. If physical separation is not maintained between these circuits, demonstrate that faults within these circuits cannot degrade both redundant trains.

The applicants confirmed that physical separation is maintained between redundant trains in the main control board, reactor trip switchgear, and reactor protection logic for the shunt trip circuitry. The reactor trip switches on the main control board have barriers to separate redundant train switch contact decks. Shunt trip attachments interposing relays and their associated terminal blocks are mounted in separate metal enclosures. The reactor protection logic outputs for energizing the shunt trip interposing relays are housed in separate metal enclosures. Physical separation for field cabling between the redundant trains is maintained. The staff finds that this design conforms to the guidance of RG 1.75 and is, therefore, acceptable.

I. Verify that the operability of the control room manual reactor trip switch contacts and wiring will be adequately tested before startup after each refueling outage. Verify that the test procedure used will not involve installing jumpers, lifting leads, or pulling fuses, and identify any deviations from the WOG procedure. Permanently installed test connections (i.e., to allow connection of a voltmeter) are acceptable.

The applicants state that the operability of the control room manual reactor trip switch contacts and wiring will be adequately tested before startup after each refueling outage. The test procedures will not involve installing jumpers, lifting leads, or pulling fuses. The staff finds this is acceptable.

J. Verify that each bypass breaker will be tested to demonstrate its operability before placing it into service for reactor trip breaker (RTB) testing.

The applicants state that frequent testing of each bypass breaker is not warranted as the occurrence of a combined event (one main RTB in test, opposite main RTB failure, and the requirement for a reactor trip) is relatively low. Therefore, the applicants do not propose to verify the operability of each bypass breaker before placing it in service each time the RTB is tested. The applicants commit to verify the operability of the undervoltage trip attachment of the bypass breakers after each refueling outage.

In previous reviews of the Westinghouse design, the staff had required that the shunt trip attachments of bypass breakers be tested with the breaker in the test position before racking in and closing of a bypass breaker for RTB testing. The basis for this requirement was that it provided a readily available means to confirm the operability of the shunt trip attachment of the bypass breakers. In addition, it was recognized that, in general, the Westinghouse design for bypass breakers does not include features that would readily permit testing of the undervoltage trip attachments. Therefore, although the shunt trip attachments for bypass breakers are not actuated on an automatic reactor trip, verification of their operability before the on-line testing of RTBs provides assurance that bypass breakers could be tripped via the manual reactor trip switches in the control room.

The staff finds that confirmation of the operability of the bypass breaker undervoltage trip attachment after each refueling outage is acceptable. The proposal of not verifying the operability of each bypass breaker shunt trip attachment before placing it in service each time the reactor trip breakers are tested was not acceptable. Subsequently, the staff reviewed the proof-and-review Technical Specifications and finds that the operability of each bypass breaker shunt trip attachment will be verified before placing it in service for the reactor trip breaker testing. This is, therefore, acceptable.

K. Verify that the test procedure used to determine reactor trip breaker operability will also demonstrate proper operation of the associated control room indication/annunciation.

The applicants note that the test procedure used to determine reactor trip breaker operability demonstrates proper operation of the associated control room indication/annunciation. The staff finds this is acceptable.

L. Verify that the response time of the automatic shunt trip feature will be tested periodically and shown to be less than or equal to that assumed in the FSAR analyses or that specified in the Technical Specifications.

The applicants state that, currently, the WOG has a life-cycle testing program for undervoltage trip attachments and shunt trip attachments. Should the testing program indicate that the breaker response time degrades with operation, then periodic on-line testing will be considered. The staff finds this commitment acceptable.

M. Propose Technical Specification changes to require periodic testing of the undervoltage and shunt trip functions and the manual reactor trip switch contacts and wiring.

The staff has reviewed the proof-and-review Technical Specifications and finds that they conform to the staff's periodic testing requirement and are, therefore, acceptable.

Conclusion

On the basis of the review of the applicants' response to the plant-specific questions identified in the staff's evaluation of the WOG generic design modifications, the staff finds the modifications are acceptable. Generic Letter 83-28 Action Items 2.1(1), 2.1(2), 2.2.1, 2.2.2, 3.1.1, 3.1.2, 3.2.1, 3.2.2, 4.1, 4.2.1, 4.2.2, 4.2.3, 4.2.4, 4.5.1, 4.5.2, and 4.5.3 will be addressed in a future evaluation. Resolution of this item is not required before the issuance of an operating license and will be accomplished in the post-licensing period.

Table 15.1 PWR parameter list

Sequence of events (SOE) recorder	Time history recorder	Parameter/signal
(1) x		Reactor trip
(1) x		Safety injection
x		Containment isolation
(1) x		Turbine trip
x		Control rod position
(1) x	x	Neutron flux, power
x	x	Containment pressure
(2)		Containment radiation
	x	Containment sump level
(1) x	x	Primary system pressure
(1) x	x	Primary system temperature
(1) x		Pressurizer level
(1) x		Reactor coolant pump status
(1) x	x	Primary system flow
(3)		Safety injection; flow, pump/valve status
x		MSIV position
x	x	Steam generator pressure
(1) x	x	Steam generator level
(1) x	x	Feedwater flow
(1) x	x	Steam flow
(3)		Auxiliary feedwater system: flow, pump/valve status
x		AC and dc system status (bus voltage)
x		Diesel generator status (start/stop, on/off)
x		PORV position

(1) Trip parameters.
(2) Parameter may be monitored by either an SOE or time history recorder.
(3) Acceptable recorder options are (a) system flow recorded on an SOE recorder, (b) system flow recorded on a time history recorder, or (c) equipment status recorded on an SOE recorder.

16 TECHNICAL SPECIFICATIONS

Two additional Technical Specifications relating to pressure isolation leak rate limits and the collection of operational data on the excore detectors have been added to updated Table 16.1.

Table 16.1 Issues to be included in Harris Technical Specifications

Issue	Applicable SER section(s)
(1) Watertight and airtight doors normally closed	2.4.2.2, 2.4.14
(2) Defining procedures to ensure that sediment deposition does not adversely affect the emergency water supply	2.4.11
(3) Monitoring of reservoir level for 2 years	2.5.2.6
(4) Compliance with provisions of RG 1.127	2.5.6.7, 2.2.6.9
(5) Regulating rod insertion controlled by power-dependent insertion limit	4.3
(6) Wide Δ I band	4.3.2
(7) Reactor coolant system flow monitored every 24 hours	4.4.3.3.1
(8) Revision of flow uncertainties	4.4.3.3.1
(9) Rod bow provisions	4.4.3.3.3
(10) Loose parts monitoring system alarm setpoints	4.4.4
(11) Provisions prohibiting N-1 loop operation	4.4.6.4
(12) Leakage through valves serving as pressure isolation boundaries (inventory balance)	5.2.5
(13) Requirements from modifications to D4 steam generators	5.4.2.2.2
(14) Periodic leak integrity tests	6.2.4
(15) Demonstrate need for continuous operation of the normal containment purge system	6.2.4
(16) Containment isolation setpoint pressure	6.2.4
(17) Limit on control room pressure flow to less than or equal to 142 cfm at pressures greater than 1/8 in. water gauge	6.4
(18) Trip set point methodology	7.2.2.2
(19) Response time testing	7.2.2.3
(20) Testing of spare CCW pump breaker and surge tank level instrumentation	7.3.3.9
(21) Testing of spare charging pump breaker	7.3.3.10
(22) Periodic testing of safety-related portion of the service water system and CCW system	9.2.1, 9.2.2
(23) Periodic testing of the ESCWS	9.2.7
(24) Post-maintenance test on emergency diesel generator in accordance with the surveillance requirements of the Standard Technical Specifications	9.5.4.1
(25) Outage time with two and three auxiliary feedwater pumps inoperable	10.4.9

Table 16.1 (Continued)

Issue	Applicable SER section(s)
(26) Flow test after cold shutdown to verify normal AFW system flow path	10.4.9
(27) Process and effluent monitoring system	11.5.2
(28) Minimum containment pressure	6.2.1.5
(29) Pressure isolation valve leak rate	3.9.6
(30) Excore detectors	4.3

APPENDIX A

CONTINUATION OF CHRONOLOGY OF NRC STAFF RADIOLOGICAL REVIEW OF SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1

April 15, 1983	Letter from applicants regarding postaccident monitoring instrumentation (RG 1.97).
October 12, 1983	Letter from applicants regarding design of component supports.
November 7, 1983	Letter from applicants regarding post-trip review program.
November 15, 1983	Letter from applicants regarding design of component supports.
November 18, 1983	Letter from applicants regarding reactor trip system.
April 15, 1985	Letter from applicants responding to question on fire protection.
May 7, 1985	Letter from applicants regarding loss-of-coolant-accident reanalysis.
May 7, 1985	Letter from applicants transmitting information concerning rod drop analysis.
May 9, 1985	Letter from applicants requesting amendment of construction permit related to request to reflect exemption from General Design Criterion (GDC) 4.
May 9, 1985	Letter from applicants modifying request for exemption from GDC 4 - request schedular exemption in lieu of permanent exemption.
May 10, 1985	Letter from applicants transmitting Amendment 20 to Final Safety Analysis Report (FSAR).
May 13, 1985	Letter from applicants regarding core damage assessment procedure.
May 13, 1985	Letter from applicants regarding emergency diesel generators.
May 13, 1985	Letter from applicants concerning minimum containment pressure.
May 21, 1985	Letter to applicants regarding Technical Specifications.

May 21, 1985	Issuance of Notice of Environmental Assessment and Finding of No Significant Impact (concerning request for exemption from GDC 4).
May 24, 1985	Letter to Westinghouse advising that January 14, 1985, submittal will be withheld from public disclosure.
May 31, 1985	Letter from applicants superseding previous letters regarding request for GDC 4 exemption and construction permit amendment.
June 3, 1985	Letter from applicants regarding RG 1.97.
June 6, 1985	Letter to applicants transmitting exemption from portion of GDC 4.
June 6, 1985	Letter from applicants forwarding information on Technical Specifications.
June 10, 1985	Letter from applicants regarding automatic shunt trip modification.
June 13, 1985	Letter from applicants regarding integrated design inspection.
June 14, 1985	Issuance of Amendment 4 to Construction Permit CPPR-158 regarding GDC 4 exemption.
June 17, 1985	Letter from applicants concerning resolution of unresolved safety issues regarding steam generator tube integrity (Generic Letter 85-02).
June 18-19, 1985	Caseload Forecast Panel Visit.
June 19, 1985	Letter from applicants regarding electrical separation analysis.
June 19, 1985	Letter to applicants transmitting Supplement No. 2 to SER.
June 28, 1985	Letter from applicants transmitting print-ready blue line of emergency preparedness public information brochure.
July 2, 1985	Letter from applicants transmitting report of their review of operability of containment purge and vent valves.
July 5, 1985	Letter from applicants regarding review of Technical Specifications.
July 8, 1985	Letter from applicants transmitting Change 2 to North Carolina Emergency Response Plan.
July 8, 1985	Letter from applicants transmitting Revision 4 of the emergency plan.

July 16, 1985	Letter from applicants transmitting additional information concerning reactor vessel level indicating system.
July 19, 1985	Letter from applicants regarding adequacy of clearances between buildings.
July 19, 1985	Meeting with applicants to discuss superheat consideration during postulated main steamline break.
August 7, 1985	Memorandum from FEMA regarding emergency plans.
August 5, 1985	Letter from applicants concerning loose parts monitoring system calibration.
August 15, 1985	Meeting with applicants to discuss containment sump pump.
August 15, 1985	Letter to applicants advising of acceptability of technical justification for elimination of arbitrary intermediate pipe breaks.
August 21, 1985	Letter from applicants requesting authorization for use of American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Cases N-411 and N-397.
August 21, 1985	Board Notification 85-078--Interim Findings on Offsite Radiological Emergency Response (RER) Plans and Preparedness.
August 26, 1985	Letter from applicants advising of schedule for submittal of information for detailed control room design review.
August 27, 1985	Board Notification 85-081--Allegations Concerning Westinghouse Analysis and QA.
August 29, 1985	Letter from applicants requesting meeting to discuss containment recirculation sump issues.
September 3, 1985	Letter from applicants transmitting information in response to TMI Action Plan Item II.K.3.5 and Generic Letter 85-12.
September 4, 1985	Letter from applicants transmitting process control program for review.
September 5, 1985	Meeting with applicants to discuss contention on drug allegation.
September 10, 1985	Letter from applicants transmitting Amendment 22 to FSAR.
September 11, 1985	Board Notification 85-082--Transcript of September 5, 1985, Meeting on Contention Concerning Alleged Use of Drugs at the Site.
September 13, 1985	Letter from applicants concerning cold shutdown capability.

September 18, 1985	Meeting with applicants to discuss design adequacy of the containment sump.
September 19, 1985	Letter from applicants forwarding information concerning drug abuse contention.
September 20, 1985	Letter from applicants transmitting Revision 5 to the emergency plan.
September 23, 1985	Letter from applicants transmitting additional information regarding preservice inspection program and categorization of request for relief.
September 23, 1985	Letter from applicants forwarding information on main steamline break containment.
September 25, 1985	Letter from applicants regarding potential high/low pressure interface damage in a single fire.
September 26, 1985	Letter from applicants forwarding information regarding load sequencer reliability.
September 26, 1985	Letter from applicants transmitting revised pressure/temperature curve.
September 26, 1985	Letter from applicants transmitting information on solid state logic protection system test circuit.
September 26, 1985	Letter from applicants transmitting information on ASME design documentation.
September 26, 1985	Letter from applicants regarding emergency lighting issues.
September 26, 1985	Letter from applicants regarding noble gas activity release via relief and safety valves.
September 30, 1985	Letter from applicants regarding final assessment of valves.
October 2, 1985	Board Notification 85-083--Panasonic Thermoluminescent Dosimeter (TLD).
October 2, 1985	Letter from applicants transmitting Revision 2 of security plan and contingency plan.
October 3, 1985	Letter from applicants regarding control rod reactivity worth and pseudo rod ejection tests.
October 14, 1985	Letter from applicants regarding anticipated transients without scram.
October 25, 1985	Letter to applicants providing interim guidance on Emergency Planning Standard 10 CFR 50.47(b)(12).

October 25, 1985	Letter to applicants forwarding preliminary staff findings from the pipe support design audit.
October 25, 1985	Letter to applicants transmitting safety evaluation report for the safety parameter display system.
October 25, 1985	Letter from applicants transmitting containment recirculation sump evaluation report.
October 25, 1985	Letter from applicants forwarding revisions to emergency procedures.
October 28, 1985	Letter to applicants advising of acceptability of use of ASME Code Cases N-309 and N-411.
October 30, 1985	Letter to applicants transmitting request for additional information regarding operability of containment purge and vent valves.
October 30, 1985	Letter to applicants transmitting request for additional information on initial plant test program.
November 5, 1985	Letter from applicants concerning preservice inspection of component supports.
November 5, 1985	Letter to applicants concerning selection of equipment to be audited by Pump and Valve Operability Review Team and Seismic Qualification Review Team.
November 7, 1985	Letter to applicants transmitting draft technical evaluation report on issue of Salem ATWS Item 1.2 (Generic Letter 83-38).
November 11, 1985	Letter from applicants transmitting Amendment 23 to FSAR.
November 12, 1985	Letter from applicants concerning flood protection.
November 18, 1985	Letter from applicants transmitting revisions to emergency procedures.
November 21, 1985	Letter from applicants regarding separation criteria of RG 1.97.
November 21, 1985	Meeting with applicants to conduct environmental qualification audit.
December 4, 1985	Meeting with applicants to discuss fire protection issues.
December 11, 1985	Letter from applicants regarding emergency plans.
December 12, 1985	Board Notification 85-092--Board Notification Regarding Catawba Nuclear Station, Unit 2, Diesel Generator 2B Main Bearing No. 7 Failure.

December 13, 1985	Letter to applicants transmitting draft technical evaluation report concerning detailed control room design review.
December 16, 1985	Letter from applicants regarding pipe support design guidelines.
December 23, 1985	Letter from applicants regarding transformer tap settings.
December 31, 1985	Letter from Battelle-Pacific Northwest Laboratories transmitting "Review of Transamerica Delaval Inc. Diesel Generator Owners' Group Engine Requalification Program."
January 6, 1986	Letter to applicants transmitting request for additional information.
Junuary 7, 1986	Letter from applicants regarding high/low pressure interfaces.
January 8, 1986	Letter to applicants transmitting agenda for proposed site audit of instrument and control systems to be conducted the week of January 27, 1986.
January 14, 1986	Letter to applicants transmitting agenda for proposed site audit of electrical systems to be conducted the week of January 27, 1986.
January 27, 1986	Letter from applicants concerning Pump and Valve Operability Review Team (PVORT) issues.
February 6, 1986	Letter from applicants concerning accumulator instrumentation backfit considerations.
February 13, 1986	Letter from applicants requesting approval of deviations from Section C.5.g. of BTP CMEB 9.5-1.
February 16, 1986	Letter from applicants regarding fire protection of redundant shutdown-related systems.
February 21, 1986	Letter to applicants transmitting request for additional information regarding Generic Letter 83-28, Items 4.1, 4.2, and 4.2.2.
April 4, 1986	Letter from applicants regarding fire protection program.

APPENDIX B

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APPENDIX D

ACRONYMS AND INITIALISMS

ACP	auxiliary control panel
ACR	auxiliary control room
AFW	auxiliary feedwater
AH	air handling
AISC	American Institute of Steel Construction
ANSI	American National Standards Institute
APDMS	axial power distribution monitoring system
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient(s) without scram
AWG	American wire gauge
AWS	American Welding Society
BA	boric acid
BOP	balance of plant
BTP	Branch Technical Position
CCW	component cooling water
CFR	Code of Federal Regulations
CP&L	Carolina Power and Light Company
CST	condensate storage tank
DNB	departure from nucleate boiling
ECAPM	excore axial power monitor
ECCS	emergency core cooling system
EDO	Executive Director for Operations
EOP	emergency operating procedure
EPIA	Emergency Preparedness Implementation Appraisal
EPRI	Electric Power Research Institute
ERF	emergency response facility
ESCWS	essential services chilled water system
ESF	engineered safety feature
ESW	emergency service water
FEMA	Federal Emergency Management Agency
FSAR	final safety analysis report
FW	feedwater
GDC	general design criterion(a)
HPES	Harris Plant Engineering Section
HVAC	heating, ventilation, and air conditioning
HX	heat exchanger

ICC	inadequate core cooling
IDI	integrated design inspection
IE	Office of Inspection and Enforcement
IEEE	Institute of Electrical and Electronics Engineers
INEL	Idaho National Engineering Laboratory
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
MCC	motor control center
MCM	million circular mils
MCR	main control room
MSRV	main steam relief valve
NPSH	net positive suction head
NSSS	nuclear steam supply system
PCP	process control program
PIC	process instrumentation room
PIV	pressure isolation valve
PORC	Plant Operations Review Committee
PORV	power-operated relief valve
PVORT	Pump and Valve Operability Review Team
PWR	pressurized-water reactor
QA	quality assurance
RAC	Regional Assistance Committee
RCDT	reactor coolant drain tank
RCP	reactor coolant pump
RCS	reactor coolant system
RER	radiological emergency response
RETS	radiological effluent technical specification(s)
RG	regulatory guide
RHR	residual heat removal
RTB	reactor trip breaker
SER	safety evaluation report
SG	steam generator
SI	safety injection
SOE	sequence of events
SQRT	Seismic Qualification Review Team
SRO	senior reactor operator
SRP	Standard Review Plan
SSE	safe shutdown earthquake
SSA	safe shutdown analysis
STA	shift technical advisor
SV	safety valve
TER	technical evaluation report
TLD	thermoluminescent dosimeter
TMI	Three Mile Island

UL	Underwriters Laboratories, Inc.
UPS	uninterruptible power supply
VR	volume reduction
WOG	Westinghouse Owners Group
WR	wide range

APPENDIX E

NRC STAFF CONTRIBUTORS

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APPENDIX H

CONFORMANCE TO REGULATORY GUIDE 1.97, SHEARON HARRIS NUCLEAR POWER PLANT, UNIT NOS. 1 & 2

CONFORMANCE TO REGULATORY GUIDE 1.97
SHEARON HARRIS NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2

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Published September 1985

EG&G Idaho, Inc.
Idaho Falls, Idaho 83415

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ABSTRACT

This EG&G Idaho, Inc., report reviews the submittals for Regulatory Guide 1.97, Revision 3, for Unit Nos. 1 and 2 of the Shearon Harris Nuclear Power Plant and identifies areas of nonconformance to the regulatory guide. Exceptions to Regulatory Guide 1.97 are evaluated and those areas where sufficient basis for acceptability is not provided are identified.

FOREWORD

This report is supplied as part of the "Program for Evaluating Licensee/Applicant Conformance to RG 1.97," being conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of Systems Integration, by EG&G Idaho, Inc., NRC Licensing Support Section.

The U.S. Nuclear Regulatory Commission funded the work under authorization B&R 20-19-40-41-3.

Docket Nos. 50-400 and 50-401

CONTENTS

CONFORMANCE TO REGULATORY GUIDE 1.97
SHEARON HARRIS NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2

1. INTRODUCTION

On December 17, 1983, Generic Letter No. 82-33 (Reference 1) was issued by D. G. Eisenhut, Director of the Division of Licensing, Nuclear Reactor Regulation, to all licensees of operating reactors, applicants for operating licenses and holders of construction permits. This letter included additional clarification regarding Regulatory Guide 1.97, Revision 2 (Reference 2) relating to the requirements for emergency response capability. These requirements have been published as Supplement No. 1 to NUREG-0737, "TMI Action Plan Requirements" (Reference 3).

Carolina Power and Light Company, the applicant for the Shearon Harris Nuclear Power Plant, Unit Nos. 1 and 2, provided a response to the generic letter on April 15, 1983 (Reference 4). The letter with their position with respect to Regulatory Guide 1.97 was submitted on September 6, 1983 (Reference 5). Additional information was submitted on June 3, 1985 (Reference 6).

This report provides an evaluation of these submittals.

2. REVIEW REQUIREMENTS

Section 6.2 of NUREG-0737, Supplement No. 1, sets forth the documentation to be submitted in a report to NRC describing how the applicant complies with Regulatory Guide 1.97 as applied to emergency response facilities. The submittal should include documentation that provides the following information for each variable shown in the applicable table of Regulatory Guide 1.97.

1. Instrument range
2. Environmental qualification
3. Seismic qualification
4. Quality assurance
5. Redundance and sensor location
6. Power supply
7. Location of display
8. Schedule of installation or upgrade

Furthermore, the submittal should identify deviations from the regulatory guide and provide supporting justification or alternatives.

Subsequent to the issuance of the generic letter, the NRC held regional meetings in February and March 1983, to answer licensee and applicant questions and concerns regarding the NRC policy on this subject. At these meetings, it was noted that the NRC review would only address exceptions taken to Regulatory Guide 1.97. Furthermore, where licensees or applicants explicitly state that instrument systems conform to the regulatory guide it was noted that no further staff review would be necessary. Therefore, this report only addresses exceptions to Regulatory Guide 1.97. The following evaluation is an audit of the applicant's submittals based on the review policy described in the NRC regional meetings.

3. EVALUATION

The applicant provided a response to Section 6.2 of NRC Generic Letter 82-33 on September 6, 1983 and additional information on June 3, 1985. This evaluation is based on these submittals.

3.1 Adherence to Regulatory Guide 1.97

The applicant states that their submittal provides a detailed account of the conformance of the Shearon Harris Nuclear Power Plant, Unit Nos. 1 and 2, to the recommendations of Revision 3 of Regulatory Guide 1.97 (Reference 7). The applicant further states that the information provided in their submittal meets the requirements of Supplement No. 1 to NUREG-0737, Section 6. Therefore, we conclude that the applicant has provided an explicit commitment on conformance to Regulatory Guide 1.97. Exceptions to and deviations from the regulatory guide are noted in Section 3.3.

3.2 Type A Variables

Regulatory Guide 1.97 does not specifically identify Type A variables, i.e., those variables that provide information required to permit the control room operator to take specific manually controlled safety actions. The applicant classifies the following instrumentation as Type A.

1. Reactor coolant system (RCS) hot leg water temperature

2. RCS cold leg water temperature

3. RCS pressure

4. Core exit temperature

5. Neutron flux

6. Containment water level

7. Containment hydrogen concentration

8. Containment pressure

9. Refueling water storage tank (RWST) level

10. Pressurizer level

11. Steam generator level (narrow range)

12. Steamline pressure

13. Auxiliary feedwater flow

14. Condensate storage tank (CST) level

15. Containment spray additive tank level

The above variables meet the Category 1 recommendations consistent with the requirements for Type A variables, except as noted in Section 3.3.

3.3 Exceptions to Regulatory Guide 1.97

The applicant identified deviations and exceptions from Regulatory Guide 1.97. These are discussed in the following paragraphs.

3.3.1 Neutron Flux

In Reference 5, the applicant indicated that their source and intermediate range neutron flux monitors that do not meet Category 1 requirements as recommended by Regulatory Guioe 1.97. The applicant stated that this variable was still under investigation.

In Reference 6, the applicant committed to the installation of Category 1 instrumentation for this variable in accordance with Regulatory Guide 1.97.

3.3.2 RCS Soluble Boron Concentration

Regulatory Guide 1.97 recommends a range of 0 to 6000 ppm for this variable. The applicant has instrumentation that covers a range of 0 to 5000 ppm. The applicant's justification is that this boron meter is adequate for any anticipated boron concentration.

The applicant deviates from Regulatory Guide 1.97 with respect to post-accident sampling capability. This deviation goes beyond the scope of this review and is being addressed by the NRC as part of their review of NUREG-0737, Item II.B.3.

3.3.3 RCS Hot and Cold Leg Water Temperature

The Shearon Harris reactors are three loop reactors. Each reactor loop has an indication of temperature for both the hot leg and the cold leg; however, in Reference 5, the applicant states that only temperatures of two loops are continuously displayed while the temperatures of the third loop is displayed on demand at the Emergency Response Facilities Information System (ERFIS) computer.

In Reference 6, the applicant has committed to provide continuous indication of the temperature of the third loop on the main control board for these variables.

3.3.4 Radioactivity Concentration or Radiation Level in Circulating Primary Coolant

The applicant has a Category 3 gross failed fuel detector that monitors delayed neutron precursors. The applicant states that if the detector is not available, grab samples may be taken via the post-accident sampling system (PASS) for laboratory analysis.

Based on the alternate instrumentation provided by the applicant, we conclude that the instrumentation supplied for this variable is adequate and, therefore, acceptable.

3.3.5 Accumulator Tank Level and Pressure

Regulatory Guide 1.97 recommends Category 2 instrumentation for these variables with a level range that monitors 10 to 90 percent of volume. The applicant has provided instrumentation that, except for environmental qualification, is Category 2. The level range monitored is between 64.1 and 71.2 percent of the accumulator volume. The applicant states that the tank level and pressure are monitored in accordance with technical specifications during normal operation. The applicant does not expect any post-accident operator action based on these variables and states that the tank status can be inferred from the RCS pressure.

The existing instrumentation is not acceptable. An environmentally qualified instrument is necessary to monitor the status of these tanks. If pressure is the key variable, and is environmentally qualified, the existing level range is acceptable. If accumulator level is considered the key variable then the range should be expanded to meet the regulatory guide recommendation in addition to being environmentally qualified.

3.3.6 Quench Tank Temperature

Regulatory Guide 1.97 recommends a temperature range of 50 to 750°F for this variable. The applicant has provided a range of 50 to 250°F. The applicant states, in Reference 5, that the tank design pressure and rupture disk relief pressure are 100 psig. This corresponds to a saturation temperature of approximately 338°F. In Reference 6, the applicant states that this tank is non-safety and only provides a reservoir for several radioactive fluids. Direct position indication of the pressurizer safety and relief valves is provided, along with temperature indication on the discharge header from the pressurizer relief and safety valve discharge lines.

Based on the justification and alternate instrumentation provided by the applicant, we conclude that the instrumentation supplied for this variable is adequate and, therefore, acceptable.

3.3.7 Steam Generator Level

In Reference 5, the applicant lists 0 to 100 percent for the range of both narrow and wide range level instrumentation. No reference is made as to what part of the steam generator these instruments are monitoring. The applicant states that the wide-range transmitters may be supplemented by the redundant narrow range transmitters on each steam generator. The applicant also states that diversity is provided by use of steamline pressure and auxiliary feedwater flow. In Reference 6, the applicant states that their wide range steam generator level instrumentation meets the range recommended by Regulatory Guide 1.97

3.3.8 Makeup Flow-In
Letdown Flow-Out
Volume Control Tank Level

The applicant takes exception to the environmental qualification recommendation of Regulatory Guide 1.97 for these variables. The justification provided by the applicant for this deviation is that these variables are not required for safe plant shutdown and the system is isolated by plant protection signals.

As these variables are not utilized in conjunction with a safety system, we find that the instrumentation provided is acceptable.

3.3.9 Component Cooling Water (CCW) Flow to Engineered Safety Features (ESF) System

Regulatory Guide 1.97 recommends Category 2 instrumentation for this variable. Category 3 instrumentation is provided. The applicant considers CCW flow to be a backup variable to the exiting Category 2 key variables which demonstrate CCW flow. These key variables are CCW heat exchanger outlet temperature and pressure, CCW pump status and CCW flow leaving the containment from the reactor coolant pumps. These variables are monitored on the main control board.

We find the applicant's justification acceptable. The temperature and pressure indication in conjunction with the CCW pumps status and the reactor coolant pump cooling water flow status adequately monitor this system.

4. CONCLUSIONS

Based on our review, we find that the applicant either conforms to or is justified in deviating from Regulatory Guide 1.97, with the following exception:

1. Accumulator tank level and pressure--environmental qualification should be addressed in accordance with 10 CFR 50.49. If accumulator level is determined to be the key variable the range should be expanded (Section 3.3.5).

5. REFERENCES

1. NRC letter, D. G. Eisenhut to All Licensees of Operating Reactors, Applicants for Operating Licenses, and Holders of Construction Permits, "Supplement No. 1 to NUREG-0737--Requirements for Emergency Response Capability (Generic Letter No. 82-33)," December 17, 1982.

2. Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, Regulatory Guide 1.97, Revision 2, U.S. Nuclear Regulatory Commission (NRC), Office of Standards Development, December 1980.

3. Clarification of TMI Action Plan Requirements, Requirements for Emergency Response Capability, NUREG-0737 Supplement No. 1, NRC, Office of Nuclear Reactor Regulation, January 1983.

4. Carolina Power and Light Company Letter, E. E. Utley to Director, Office of Nuclear Reactor Regulation, April 15, 1983.

5. Carolina Power and Light Company Letter, M. A. McDuffie to Director, Office of Nuclear Reactor Regulation, September 6, 1983.

6. Carolina Power and Light Company Letter, S. R. Zimmerman to H. Denton, Office of Nuclear Reactor Regulation, NRC, "Compliance with Regulatory Guide 1.97," June 3, 1985, Serial No. NLS-85-109.

7. Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, Regulatory Guide 1.97, Revision 3, U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Regulatory Research, May 1983.

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APPENDIX I

CONFORMANCE TO GENERIC LETTER 83-28 ITEMS 3.1.3 AND 3.2.3
SHEARON HARRIS UNIT 1

CONFORMANCE TO GENERIC LETTER 83-28
ITEMS 3.1.3 AND 3.2.3
SHEARON HARRIS UNIT 1

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ABSTRACT

This EG&G Idaho, Inc., report provides a review of the submittals from Shearon Harris Unit 1 for conformance to Generic Letter 83-28, items 3.1.3 and 3.2.3.

FOREWORD

This report is supplied as part of the program for evaluating licensee/applicant conformance to Generic Letter 83-28 "Required Actions Based on Generic Implications of Salem ATWS Events." This work is being conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of System Integration by EG&G Idaho, Inc., NRR and I & E Support Branch.

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Docket No. 50-400

CONTENTS

CONFORMANCE TO GENERIC LETTER 83-28
ITEMS 3.1.3 AND 3.2.3
SHEARON HARRIS UNIT 1

1. INTRODUCTION

On July 8, 1983, Generic Letter No. 83-28[1] was issued by D. G. Eisenhut, Director of the Division of Licensing, Nuclear Reactor Regulation, to all licensees of operating reactors, applicants for operating licenses, and holders of construction permits. This letter included required actions based on the generic implications of the Salem ATWS events. These requirements have been published in Volume 2 of NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant".[2]

This report documents the EG&G Idaho, Inc. review of the submittals from Shearon Harris Unit 1 for conformance to items 3.1.3 and 3.2.3 of Generic Letter 83-28. The submittals and other documents utilized in this evaluation are referenced in Section 4 of this report.

2. REVIEW REQUIREMENTS

Item 3.1.3 (Post-Maintenance Testing of Reactor Trip System Components) requires licensees and applicants to identify, if applicable, any post-maintenance test requirements for the reactor trip system (RTS) in existing technical specifications which can be demonstrated to degrade rather than enhance safety. Item 3.2.3 applies this same requirement to all other safety-related components. Any proposed technical specification changes resulting from this action shall receive a pre-implementation review by NRC.

The relevant submittals for Shearon Harris Unit 1 were reviewed to determine compliance with items 3.1.3 and 3.2.3 of the generic letter. First, the submittals from this plant were reviewed to determine that these two items were specifically addressed. Second, the submittals were checked to determine if any post-maintenance test items specified in the technical specifications were identified that were suspected to degrade rather than enhance safety. Last, the submittal was reviewed for evidence of special conditions or other significant information relating to the two items of concern.

3. REVIEW RESULTS FOR SHEARON HARRIS UNIT 1

3.1 Evaluation

Carolina Power and Light Co., the applicant for Shearon Harris Unit 1, provided a response to items 3.1.3 and 3.2.3 of Generic Letter 83-28 in their submittal dated November 7, 1983[3]. The submittal indicated that the technical specifications and post-maintenance test procedures were undergoing development. Completion was scheduled for June, 1985. The applicant stated that any standardized technical specifications (used to develop the technical specifications for Shearon Harris Unit 1) that are perceived to degrade rather than enhance safety would be identified during the submission of the plant specific technical specifications.

In their subsequent submittal dated May 31, 1985[4], the applicant stated that a draft version of their technical specifications for Shearon Harris Unit 1 had been submitted to the NRC on April 23, 1985. They also stated that the technical specifications would continue to undergo detailed review to assess implementation of the required surveillance and to verify that the tests required following maintenance do not damage the components being tested.

3.2 Conclusion

The applicant's submittals meet the requirements of items 3.1.3 and 3.2.3 of Generic Letter 83-28 and are acceptable.

4. REFERENCES

1. NRC Letter, D. G. Eisenhut to all Licensees of Operating Reactors, Applicants for Operating License, and Holders of Construction Permits, "Required Actions Based on Generic Implications of Salem ATWS Events (Generic Letter 83-28)", July 8, 1983.

2. Generic Implications of ATWS Events at the Salem Nuclear Power Plant, NUREG-1000, Volume 1, April 1983; Volume 2, July 1983.

3. Letter, A. B. Cutter, Carolina Power and Light Co., to D. G. Eisenhut, NRC, November 7, 1983.

4. Letter, S. R. Zimmerman, Carolina Power and Light Co., to H. R. Denton, NRC, May 31, 1985.

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Docket No. 50-400

13. ABSTRACT *(200 words or less)*

Supplement No. 3 to the Safety Evaluation Report for the application filed by Carolina Power and Light Company, et al., for license to operate the Shearon Harris Nuclear Power Plant, Unit No. 1, located in Wake County, North Carolina, has been prepared by the Office of Nuclear Reactor Regulation of the Nuclear Regulatory Commission. The purpose of this supplement is to update the Safety Evaluation Report of (1) additional information submitted by the applicants since Supplement No. 2 was issued, and (2) matters that the staff had under review when Supplement No. 2 was issued.

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