NUREG-1038
Supplement No. 4

# 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 Regulation**

October 1986

## NOTICE

### Availability of Reference Materials Cited in NRC Publications

Most documents cited in NRC publications will be available from one of the following sources:

1. The NRC Public Document Room, 1717 H Street, N.W.
   Washington, DC 20555
2. The Superintendent of Documents, U.S. Government Printing Office, Post Office Box 37082, Washington, DC 20013-7082
3. The National Technical Information Service, Springfield, VA 22161

Although the listing that follows represents the majority of documents cited in NRC publications, it is not intended to be exhaustive.

Referenced documents available for inspection and copying for a fee from the NRC Public Document Room include NRC correspondence and internal NRC memoranda; NRC Office of Inspection and Enforcement bulletins, circulars, information notices, inspection and investigation notices; Licensee Event Reports; vendor reports and correspondence; Commission papers; and applicant and licensee documents and correspondence.

The following documents in the NUREG series are available for purchase from the GPO Sales Program: formal NRC staff and contractor reports, NRC-sponsored conference proceedings, and NRC booklets and brochures. Also available are Regulatory Guides, NRC regulations in the *Code of Federal Regulations,* and *Nuclear Regulatory Commission Issuances.*

Documents available from the National Technical Information Service include NUREG series reports and technical reports prepared by other federal agencies and reports prepared by the Atomic Energy Commission, forerunner agency to the Nuclear Regulatory Commission.

Documents available from public and special technical libraries include all open literature items, such as books, journal and periodical articles, and transactions. *Federal Register* notices, federal and state legislation, and congressional reports can usually be obtained from these libraries.

Documents such as theses, dissertations, foreign reports and translations, and non-NRC conference proceedings are available for purchase from the organization sponsoring the publication cited.

Single copies of NRC draft reports are available free, to the extent of supply, upon written request to the Division of Technical Information and Document Control, U.S. Nuclear Regulatory Commission, Washington, DC 20555.

Copies of industry codes and standards used in a substantive manner in the NRC regulatory process are maintained at the NRC Library, 7920 Norfolk Avenue, Bethesda, Maryland, and are available there for reference use by the public. Codes and standards are usually copyrighted and may be purchased from the originating organization or, if they are American National Standards, from the American National Standards Institute, 1430 Broadway, New York, NY 10018.

NUREG-1038
Supplement No. 4

# 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 Regulation**

October 1986

ABSTRACT

This report, Supplement No. 4 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, 2, and 3.

TABLE OF CONTENTS


| | Page |
|---|---|
| Abstract | iii |
| 1 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT | 1-1 |
| 1.1 Introduction | 1-1 |
| 1.7 Outstanding Issues | 1-1 |
| 1.8 Confirmatory Issues | 1-2 |
| 1.9 License Conditions | 1-2 |
| 1.10 Miscellaneous Items | 1-2 |
| 2 SITE CHARACTERISTICS | 2-1 |
| 2.4 Hydrologic Engineering | 2-1 |
| 2.4.2 Floods | 2-1 |
| 2.4.2.2 Effect of Local Intense Precipitation | 2-1 |
| 2.4.11 Cooling Water Supply | 2-3 |
| 2.4.11.1 Normal Water Supply | 2-3 |
| 2.4.11.2 Emergency Water Supply | 2-3 |
| 2.4.14 Technical Specifications and Emergency Operation Requirement | 2-3 |
| 2.5 Geology and Seismology | 2-4 |
| 2.5.6 Embankments, Dams, and Channels | 2-4 |
| 2.5.6.7 Instrumentation | 2-4 |
| 3 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS | 3-1 |
| 3.2 Classification of Structures, Systems, and Components | 3-1 |
| 3.2.2 System Quality Group Classification | 3-1 |
| 3.5 Missile Protection | 3-1 |
| 3.5.1 Missile Selection and Description | 3-1 |
| 3.5.1.3 Turbine Missiles | 3-1 |

TABLE OF CONTENTS (Continued)


| | Page |
|---|---|
| 3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping | 3-2 |
| 3.6.1 Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment | 3-2 |
| 3.8 Design of Seismic Category I Structures | 3-3 |
| 3.9 Mechanical Systems and Components | 3-4 |
| 3.9.3 ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures | 3-4 |
| 3.9.3.2 Design and Installation of Pressure Relief Devices | 3-4 |
| 3.9.6 Inservice Testing of Pumps and Valves | 3-5 |
| 3.10 Seismic and Dynamic Qualification of Safety-Related Mechanical and Electrical Equipment | 3-5 |
| 3.10.1 Operability Qualification of Mechanical and Electrical Equipment | 3-5 |
| 3.10.1.1 Introduction | 3-5 |
| 3.10.1.2 Discussion | 3-6 |
| 3.10.1.3 Operability Issues | 3-7 |
| 3.10.1.4 Summary | 3-9 |
| 3.10.2 Seismic and Dynamic Qualification of Electrical and Mechanical Equipment | 3-10 |
| 3.10.2.1 Generic Items | 3-11 |
| 3.10.2.2 Equipment-Specific Items | 3-12 |
| 3.10.2.3 Summary and Conclusions | 3-12 |
| 3.11 Environmental Qualification of Mechanical and Electrical Equipment | 3-12 |
| 3.11.1 Introduction | 3-12 |
| 3.11.2 Background | 3-13 |
| 3.11.3 Staff Evaluation | 3-13 |
| 3.11.3.1 Completeness of Equipment Important to Safety | 3-14 |
| 3.11.3.2 Qualification Methods | 3-15 |
| 3.11.3.3 Service Conditions | 3-16 |
| 3.11.3.4 Outstanding Equipment | 3-18 |

TABLE OF CONTENTS (Continued)


| | | | Page |
|---|---|---|---|
| | 3.11.4 | Environmental Qualification Audit | 3-18 |
| | 3.11.5 | Conclusions | 3-19 |
| 4 | REACTOR | | 4-1 |
| | 4.3 | Nuclear Design | 4-1 |
| | 4.3.2 | Design Description | 4-1 |
| | 4.3.5 | Moderator Temperature Coefficient | 4-1 |
| | 4.4 | Thermal-Hydraulic Design | 4-4 |
| | 4.4.3 | Design Abnormalities | 4-4 |
| | 4.4.3.1 | Crud Deposition | 4-4 |
| | 4.4.6 | NUREG-0737 Item II.F.2, Instrumentation for Inadequate Core Cooling Detection | 4-4 |
| 5 | REACTOR COOLANT SYSTEM | | 5-1 |
| | 5.2 | Integrity of Reactor Coolant Pressure Boundary | 5-1 |
| | 5.2.2 | Overpressure Protection | 5-1 |
| | 5.2.2.2 | Overpressure Protection During Low-Temperature Operation | 5-1 |
| | 5.2.4 | Reactor Coolant Pressure Boundary Inservice Inspection and Testing | 5-1 |
| | 5.2.4.3 | Evaluation of Compliance With 10 CFR 50.55(g) | 5-1 |
| | 5.3 | Reactor Vessel | 5-2 |
| | 5.3.4 | Pressurized Thermal Shock | 5-2 |
| | 5.4 | Component and Subsystem Design | 5-4 |
| | 5.4.2 | Steam Generators | 5-4 |
| | 5.4.2.2 | Steam Generator Tube Inservice Inspection | 5-4 |
| | 5.4.7 | Residual Heat Removal System | 5-5 |
| | 5.4.7.5 | Tests, Operational Procedures, and Support Systems | 5-5 |

TABLE OF CONTENTS (Continued)


| | | |
|---|---|---|
| | | Page |
| 6 | ENGINEERED SAFETY FEATURES | 6-1 |
| | 6.2 Containment Systems | 6-1 |
| | 6.2.4 Containment Isolation System | 6-1 |
| | 6.2.6 Containment Leakage Testing Program | 6-1 |
| | 6.3 Emergency Core Cooling System | 6-4 |
| | 6.3.5 Performance Evaluation | 6-4 |
| | 6.3.5.1 Large-Break LOCA | 6-4 |
| | 6.3.5.2 Small-Break LOCA | 6-4 |
| | 6.4 Control Room Habitability | 6-4 |
| | 6.6 Inservice Inspection of Class 2 and 3 Components | 6-6 |
| | 6.6.3 Evaluation of Compliance With 10 CFR 50.55a(g) | 6-6 |
| 7 | INSTRUMENTATION AND CONTROLS | 7-1 |
| | 7.3 Engineered Safety Features Systems | 7-1 |
| | 7.3.3 Evaluation Findings | 7-1 |
| | 7.3.3.9 Spare Component Cooling Water (CCW) Pump | 7-1 |
| | 7.3.3.10 Spare Charging Pump | 7-1 |
| | 7.4 Systems Required for Safe Shutdown | 7-1 |
| | 7.4.1 Description | 7-1 |
| | 7.4.1.3 Auxiliary Feedwater Control | 7-1 |
| | 7.4.2 Specific Findings | 7-2 |
| | 7.4.2.2 Testing for Remote Shutdown Operation | 7-2 |
| 8 | ELECTRICAL POWER SYSTEMS | 8-1 |
| | 8.1 General | 8-1 |
| | 8.3 Onsite Power Systems | 8-2 |
| | 8.3.1 AC Power Systems | 8-2 |
| | 8.4 Other Electrical Features and Requirements for Safety | 8-12 |
| | 8.4.2 Adequacy of Station Electric Distribution System Voltages | 8-12 |
| | 8.4.2.1 Position 1--Second-Level Undervoltage | 8-12 |

TABLE OF CONTENTS (Continued)


| | | | Page |
|---|---|---|---|
| | 8.4.8 | TMI Action Plan Requirements | 8-13 |
| 9 | | AUXILIARY SYSTEMS | 9-1 |
| | 9.1 | Fuel Storage and Handling | 9-1 |
| | 9.1.5 | Overhead-Heavy-Load-Handling Systems | 9-1 |
| | 9.2 | Water Systems | 9-2 |
| | 9.2.2 | Primary Component Cooling Water System | 9-2 |
| | 9.2.7 | Essential Services Chilled Water System | 9-2 |
| | 9.3 | Process Auxiliaries | 9-3 |
| | 9.3.2 | Process Sampling System | 9-3 |
| | 9.3.2.2 | Postaccident Sampling System | 9-3 |
| | 9.5 | Other Auxiliary Systems | 9-4 |
| | 9.5.1 | Fire Protection | 9-4 |
| | 9.5.1.1 | Fire Protection Program Requirements | 9-4 |
| | 9.5.1.4 | General Plant Guidelines | 9-4 |
| | 9.5.1.5 | Fire Detection and Suppression | 9-6 |
| | 9.5.1.6 | Fire Protection of Specific Plant Areas | 9-7 |
| | 9.5.1.7 | Summary of Approved Deviations From BTP CMEB 9.5-1 | 9-8 |
| | 9.5.1.8 | Conclusion | 9-8 |
| | 9.5.4 | Emergency Diesel Engine Fuel Oil Storage and Transfer System | 9-9 |
| | 9.5.4.2 | Emergency Diesel Engine Fuel Oil Storage and Transfer System | 9-9 |
| 10 | | STEAM AND POWER CONVERSION SYSTEM | 10-1 |
| | 10.4 | Other Features | 10-1 |
| | 10.4.9 | Auxiliary Feedwater System | 10-1 |
| 11 | | RADIOACTIVE WASTE MANAGEMENT | 11-1 |
| | 11.5 | Process and Effluent Radiological Monitoring and Sampling Systems | 11-1 |
| | 11.5.2 | Evaluation and Findings | 11-1 |

TABLE OF CONTENTS (Continued)


Page

13 CONDUCT OF OPERATIONS .......... 13-1

13.1 Organizational Structure of Applicant .......... 13-1

13.1.1 Corporate Management and Technical Support Organizations .......... 13-1

13.1.1.1 Nuclear Generation Group .......... 13-2
13.1.1.2 Operations Support Group .......... 13-3
13.1.1.3 Quality Assurance Department .......... 13-5
13.1.1.4 Personnel Qualifications .......... 13-6
13.1.1.5 Conclusions .......... 13-6

13.1.2 Operating Organization .......... 13-8

13.1.2.1 Project Organization .......... 13-8
13.1.2.2 Plant Operating Organization .......... 13-9
13.1.2.3 Personnel Qualifications .......... 13-10
13.1.2.4 Conclusions .......... 13-10

13.2 Training .......... 13-11

13.2.1 Licensed Operator Training Program .......... 13-11

13.5 Station Administrative Procedures .......... 13-11

13.5.1 Administrative Procedures .......... 13-11
13.5.2 Operating and Maintenance Procedures .......... 13-12

13.5.2.1 General .......... 13-12
13.5.2.3 Reanalysis of Transients and Accidents; Development of Emergency Operating Procedures .......... 13-19

13.6 Industrial Security .......... 13-20

13.6.1 Introduction .......... 13-20
13.6.2 Staff Evaluation .......... 13-20

13.6.2.1 Physical Security Organization .......... 13-20
13.6.2.2 Physical Barriers .......... 13-21
13.6.2.3 Identification of Vital Areas .......... 13-21
13.6.2.4 Access Requirements .......... 13-21
13.6.2.5 Detection Aids .......... 13-22
13.6.2.6 Communications .......... 13-22
13.6.2.7 Test and Maintenance Requirements .......... 13-23
13.6.2.8 Response Requirements .......... 13-23
13.6.2.9 Employee Screening Program .......... 13-24
13.6.2.10 Conclusion .......... 13-24

TABLE OF CONTENTS (Continued)


| | | Page |
|---|---|---|
| 14 | INITIAL TEST PROGRAM | 14-1 |
| 15 | ACCIDENT ANALYSES | 15-1 |
| | 15.6 Decrease in Reactor Coolant Inventory | 15-1 |
| | 15.6.3 Steam Generator Tube Rupture | 15-1 |
| | 15.6.5 LOCA | 15-2 |
| | 15.6.5.2 ECCS Leakage Outside Containment | 15-2 |
| | 15.8 Anticipated Transients Without Scram | 15-2 |
| | 15.9 TMI Action Plan Requirements | 15-6 |
| | 15.9.9 II.K.3.5, Automatic Trip of RCPs During LOCA | 15-6 |
| | 15.9.13 II.K.3.30, Revised Small-Break LOCA Methods To Show Compliance With 10 CFR 50, Appendix K | 15-6 |
| | 15.9.14 II.K.3.31, Plant-Specific Calculations To Show Compliance With 10 CFR 50.46 | 15-6 |
| 16 | TECHNICAL SPECIFICATIONS | 16-1 |
| 17 | QUALITY ASSURANCE | 17-1 |
| | 17.2 Organization | 17-1 |
| 18 | HUMAN FACTORS ENGINEERING | 18-1 |
| | 18.1 Detailed Control Room Design Review | 18-1 |
| | 18.1.1 Multidisciplinary Review Team | 18-2 |
| | 18.1.2 System Function and Task Analysis | 18-2 |
| | 18.1.3 Control Room Inventory | 18-2 |
| | 18.1.4 Control Room Survey | 18-2 |
| | 18.1.5 Assessment of Human Engineering Discrepancies | 18-3 |
| | 18.1.6 Selection of Design Improvements | 18-3 |
| | 18.1.7 Verification That Design Improvements Provide Necessary Correction and Do Not Introduce New HEDs | 18-3 |
| | 18.1.8 Coordination of the DCDR With Other NUREG-0737 (Supplement 1) Programs | 18-4 |
| | 18.1.9 Summary | 18-4 |
| | 18.2 Safety Parameter Display System | 18-4 |
| | 18.2.1 SPDS Description | 18-5 |
| | 18.2.2 Parameter Selection | 18-5 |
| | 18.2.3 Human Factors Program | 18-7 |
| | 18.2.4 Electrical and Electronic Isolation | 18-8 |
| | 18.2.5 System Availability | 18-8 |

## TABLE OF CONTENTS (Continued)

| | | Page |
|---|---|---|
| 18.2.6 | Verification and Validation Plan | 18-8 |
| 18.2.7 | Implementation Plan | 18-8 |
| 18.2.8 | Procedures and Training | 18-9 |
| 18.2.9 | Conclusions | 18-9 |
| 19 | REPORT OF THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS | 19-1 |


### APPENDICES

APPENDIX A Continuation of Chronology of NRC Staff Radiological Review of Shearon Harris

APPENDIX B Bibliography

APPENDIX D Acronyms and Initialisms

APPENDIX E NRC Staff Contributors and Consultants

APPENDIX J Safety Evaluation of Preservice Inspection Relief Request

APPENDIX K Control of Heavy Loads at Nuclear Power Plants

APPENDIX L Conformance to Generic Letter 83-28, Item 2.1 (Part 1), Equipment Classification (RTS Components)

APPENDIX M Technical Evaluation Report of the Detailed Control Room Design Review for Carolina Power and Light Company Shearon Harris Nuclear Power Plant, Unit 1

APPENDIX N Errata


### LIST OF FIGURES

| | Page |
|---|---|
| 13.1 CP&L organization and the Operations Support Group | 13-25 |
| 13.2 The Nuclear Generation Group and the Harris Nuclear Project | 13-26 |
| 13.3 Harris Plant Operations Section | 13-27 |
| 17.1 CP&L corporate organization | 17-4 |
| 17.2 CP&L QA organization | 17-5 |


### TABLES

| | Page |
|---|---|
| 1.2 Outstanding issues | 1-4 |
| 1.3 Confirmatory issues | 1-6 |
| 1.4 License conditions | 1-9 |

TABLES (Continued)


| | | Page |
|---|---|---|
| 3.1 | Summary of PVORT audit for the Shearon Harris Nuclear Power Plant . | 3-20 |
| 3.2 | Status of SER items for pump and valve operability assurance ...... | 3-22 |
| 16.1 | Issues resolved by inclusion in Shearon Harris Technical Specifications ............................................ | 16-2 |

# 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, hereinafter referred to as the "applicant") for a license to operate the Shearon Harris Nuclear Power Plant, Unit 1. Supplement Nos. 1, 2, and 3 were issued in June 1984, June 1985, and May 1986, respectively. This report is Supplement No. 4 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, 2, and 3.

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. Appendices J, K, L, M, and N are added to the SER in this supplement. Appendix J is a staff evaluation of the applicant's preservice inspection relief requests prepared with the assistance of the Idaho National Engineering Laboratory (INEL). Apendix K, which discusses control of heavy loads at Shearon Harris was also prepared for NRC by INEL, as was Appendix L which discusses conformance to Item 2.1 (Part 1) of the staff's Generic Letter 83-28. Appendix M is a technical evaluation report on the detailed control room design review at Shearon Harris, prepared by Lawrence Livermore National Laboratory. Appendix N corrects errors in the SER and its supplements discovered after publication.

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

Mr. Jaime Guillen, Project Engineer, assisted Mr. Buckley in the preparation of this supplement.

## 1.7 Outstanding Issues

Section 1.7 in the SER and its supplements noted that certain information had not yet been provided by the applicants for several identified items. This fourth supplement updates those items for which additional information has subsequently been provided or where revisions were made to previously closed issues. These items, and the sections of supplements discussing the review conclusions, are

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

(1) Equipment qualification (3.10, 3.11)

(2) Fire protection (9.5.1)

(3) Shift supervisor administrative duties (13.5.1)

(4) Verification of correct performance of operator activities (13.5.1)

(5) Control room design review (18)

All of the above items have now been resolved. All open items previously identified in the SER and its supplements have now been closed. Table 1.2 has been revised to reflect this.

## 1.8 Confirmatory Issues

Section 1.8 of Supplement Nos. 1, 2, and 3 to the SER stated that certain confirmatory information will be provided by the applicant. Fourteen of these items, identified as items 2, 6, 8, 9, 10, 12, 13, 17, 21, 31, 32, 33, 34, and 36 have been resolved in the cited sections of this supplement. Confirmatory item 33 discussed two items; one item, II.K.3.5, "Automatic trip of RCPs during LOCA," has been resolved for low-power operation. However, this matter will require further discussion before a decision is made on the issuance of a full-power license. All other confirmatory items previously identified in the SER and its supplements have been resolved. The confirmatory items in Section 1.8 of the SER are listed in 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, 2, and 3 listed several probable license conditions. License conditions 1, 2, 3, and 8 have been deleted, as discussed in the sections cited in Table 1.4. However, four additional proposed license conditions (11, 12, 13, and 14) been added and are discussed in the corresponding sections cited in Table 1.4.

## 1.10 Miscellaneous Items

The applicant has provided additional information on certain items that required staff review and approval. The staff review of these items, listed below, is provided in the cited sections of this supplement. All of these items have been resolved.

(1) Effect of local intense precipitation (2.4.2.2)
(2) Normal water supply (2.4.11.1)
(3) Emergency water supply (2.4.11.2)
(4) Technical Specifications and emergency operating requirement (2.4.14)
(5) Instrumentation (2.5.6.7)
(6) Moderator temperature coefficient (4.3.5)
(7) Crud deposition (4.4.3.1)
(8) Pressurized thermal shock (5.3.4)
(9) Residual heat removal system (5.4.7.5)
(10) Containment isolation system (6.2.4)
(11) Large-break LOCA (6.3.5.1)
(12) Small-break LOCA (6.3.5.2)

(13) Control room habitability (6.4)
(14) Spare component cooling water (CCW) pump (7.3.3.9)
(15) Spare charging pump (7.3.3.10)
(16) Electric power systems (8.1)
(17) AC power system (8.3.1)
(18) Physical independence of redundant safety-related systems (8.3.1)
(19) TMI Action Plan requirements (8.4.8)
(20) Primary component cooling water system (9.2.2)
(21) Essential services chilled water system (9.2.7)
(22) Emergency diesel engine fuel oil storage and transfer system (9.5.4.2)*
(23) ECCS leakage outside containment (15.6.5.2)
(24) Generic Letter 83-28 (15.8)
(25) II.K.3.30, Revised small-break LOCA methods to show compliance with
     10 CFR 50.46 (15.9.13)
(26) II.K.3.31, Plant-specific calculations to show compliance with
     10 CFR 50.46 (15.9.14)
(27) Organization (17.2)
(28) Building clearances (19)

*Numbered 9.4.5.2 (in error) in SER.

Table 1.2 Outstanding issues

| 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 | Resolved | 3.10 3.11 |
| (6) | Preservice/Inservice Inspection Program | Changed to Confirmatory Issue 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 Issue 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 | 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 |
| 1.C.6 | Verification of correct performance of operator activities | Resolved | 13.5.1 |
| I.D.1 | Control room design review | 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 | 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 | Resolved | 3.9.3.2 |
| (7) Leak rate test program for pressure isolation valves | Resolved | 3.9.6 |
| (8) Calculation of ultimate strength capacity of containment building under uniform internal pressure | Resolved | 3.8 |
| (9) Additional information on excore detectors | Resolved | 4.3 |
| (10) PORV setpoint values | Resolved | 5.2.2 |
| (11) Revised pressure-temperature curves | Resolved | 5.3.2 |
| (12) Examination of steam generators and NUREG-1014 revisions | Resolved | 5.4.2.2 |
| (13) Revision of FSAR on containment penetrations | 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 | 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 | 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 | Resolved | 13.1.1.6 |
| (32) Initial test program<br>• Additional testing to verify the capacity of the steam generator safety and relief valves<br>• Amend FSAR to incorporate additional information on AWP endurance tests<br>• Expansion of natural circulation tests to fully comply with NUREG-0737, Item I.G.1 | Resolved | 14 |

Table 1.3 (Continued)

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

*Resolved for low-power operation.
**See License Condition 10.

Table 1.4 License conditions

| License condition | Status | Section(s) |
|---|---|---|
| (1) Turbine system maintenance program | Deleted | 3.5.1.3 |
| (2) Turbine steam valve maintenance | Deleted | 3.5.1.3 |
| (3) II.B.3, Postaccident sampling system | Deleted | 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 | Deleted | 4.4.6 |
| (9) Physical security | | 13.6.3 |
| (10) Steam generator tube rupture | | 15.6.3 |
| (11) Safety parameter display system | | 18.2 |
| (12) Control room survey | | 18.1 |
| (13) Diesel generator | | 8.3.1 |
| (14) Fire protection | | 9.5.1 |

# 2 SITE CHARACTERISTICS

## 2.4 Hydrologic Engineering

### 2.4.2 Floods

#### 2.4.2.2 Effect of Local Intense Precipitation

In the FSAR, the applicant determined that flood waters from intense local precipitation could pond to an elevation that would exceed the elevation of some entrances to safety-related structures. To protect these structures from flooding, the applicant committed to use watertight or airtight doors or to build low structural barriers such as curbs to prevent water from entering the affected safety-related structures.

In Section 2.4.2.2 of the SER, the staff required that the applicant identify exterior openings where watertight or airtight doors would be used and openings where curbs would be installed. In addition, the staff required a Technical Specification to ensure that watertight doors would normally be in a closed position.

In a letter dated October 25, 1984, from S. R. Zimmerman to H. R. Denton, the applicant stated that there are only three doors at Shearon Harris which are potentially exposed to high water levels from a local probable maximum precipitation (PMP) event. Two of these doors are personnel exits and the third is a large equipment entry door. The applicant further stated that these doors are not intended for frequent, routine access and each is normally locked. In addition, each door is electronically monitored by the security system and will alarm when opened. Since the required security surveillance will ensure that the doors are normally closed, the applicant concluded that a Technical Specification would serve no useful purpose and requested that the staff delete its SER requirement for a Technical Specification to ensure that the doors are normally closed.

As stated above, the applicant committed to use airtight or watertight doors. However, in its October 25, 1984, letter, the applicant did not state whether the three exposed exterior doors met this commitment. Subsequently, in a letter dated November 12, 1985, from S. R. Zimmerman to H. R. Denton, the applicant stated that the doors are tornado-type doors with seals that will prevent the entry of floodwater.

The staff reviewed the information provided by the applicant and agrees that because the exposed exterior doors are normally closed and alarm when opened, and are tornado-type doors with seals to prevent water entry, a Technical Specification is not necessary. The staff thus concludes that with respect to surface flooding from a local PMP event, the Shearon Harris plant meets the requirements of General Design Criterion 2.

Another staff requirement in SER Section 2.4.2.2 concerned the potential for excessive ponding between a retaining wall and the fuel handling building.

Because Units 3 and 4 were cancelled, the containment buildings, reactor auxiliary buildings, and tank buildings for Units 3 and 4 will not be built. A retaining wall has been constructed west of the fuel handling building to separate the fuel handling building from the plant fill. This wall will be physically separated from the fuel handling building so it will be possible for water to pond in the area between the two structures. Ponded water will be removed to the site drainage system by sump pumps. In addition to direct rainfall and groundwater infiltrating through the retaining wall, this area will collect overflow from the roofs of the waste processing building and the fuel handling building, should the roof drains of those two buildings be blocked.

The applicant postulated a failure of the sump pumps during a PMP event and estimated that water in the area between the retaining wall and the fuel handling building would not rise above elevation 236 feet msl. All openings in the waste processing building and the fuel handling building below elevation 236 feet msl have been closed, and other penetrations have been sealed to prevent water from entering safety-related buildings.

As discussed in the SER, the staff reviewed the information provided by the applicant concerning ponding of water in the area between the retaining wall and the fuel handling building and performed an independent analysis to determine the depth of flooding in this area. On these bases, the staff concluded that during a PMP event, water would not pond higher than elevation 236 feet msl even if the sump pumps were inoperable.

The staff, however, required that the applicant provide assurance that the wall of the fuel handling building can withstand a hydrostatic level of 236 feet msl. The staff also required that the applicant describe the program to be used to ensure that the sump pumps are operable on a long-term basis. The staff's concern was that unless there were a formal program to monitor the operability of the sump pumps, it was possible for all pumps to be inoperable for a long duration and for water from normal precipitation events and from infiltrating groundwater to pond to levels higher than elevation 236 feet msl. Thus, the staff required that the applicant describe how pump operability and ponded water levels would be monitored and the actions to be taken if pumps malfunctioned or the level of ponding rose above elevation 236 feet msl.

In response to the staff's requirements, the applicant in its November 12, 1985, letter stated that the wall of the fuel handling building can withstand a hydrostatic load up to an elevation of 236 feet msl from a PMP flooding. In addition, the applicant stated that two pumps are located in each of the areas (Unit 3 area and Unit 4 area) between the retaining wall and the fuel handling building. These pumps will operate to remove water that accumulates in the respective area. Under normal conditions, water levels will be maintained at or below the 216-foot elevation. To ensure that the area above the 216 foot elevation remains free of water, the operation of each pump will be checked weekly by jogging the level control switch for each sump pump. In addition, the area will be checked after a heavy rainfall to observe removal of water from the area. If both pumps become inoperable and water accumulates to elevation 221 feet msl, additional temporary pumps will be installed to remove the accumulated water.

The staff finds this commitment acceptable to ensure that ponded water levels do not exceed the hydrostatic design basis of 236 feet for the fuel handling building. However, the staff will require that this commitment to ensure pump operability be part of the plant operating procedures.

2.4.11 Cooling Water Supply

2.4.11.1 Normal Water Supply

In the SER, the staff stated that a Technical Specification will be required to "define the average water temperature...at which the plant will be shut down." In addition to being difficult to measure, an average temperature doesn't provide the required information. Therefore, instead of requiring average temperature readings, the Technical Specifications have defined the water temperature at the intake structure, above which the plant will be shut down. The staff considers this issue resolved.

2.4.11.2 Emergency Water Supply

Plant site drainage including overland runoff flows into the emergency service water intake (ESWI) channel and the emergency service water discharge (ESWD) channel. Sediment carried by this drainage will be deposited in these channels. To preclude this sediment from building up to levels that will affect the ability of the channels to convey the required volume of emergency cooling water, the applicant committed to monitor the channels for sediment buildup in accordance with Regulatory Guide (RG) 1.127, Revision 1. In Sections 2.4.11.2 and 2.4.14 of the SER, the staff required a Technical Specification to define the depth of sediment that would be allowed to accumulate in the channels and a procedure for removing the accumulated sediment.

The applicant has been inspecting the channels in accordance with RG 1.127, Revision 1, since the auxiliary reservoir was filled in 1981. During this time, there has been very little sediment buildup and no significant change in channel flow area. The staff expects that once the plant is in operation even less sediment will accumulate in the channels because of the flowing water.

The applicant, in Technical Specification 6.8.4.f, has described the inspection program that will be implemented in accordance with RG 1.127, Revision 1. However, since very little sediment has accumulated, the applicant has proposed to examine the channels in terms of cross-sectional flow area rather than by measuring depth of sediment as required by the staff in the SER. The staff has reviewed the applicant's information and concludes that the proposed program will ensure that the ESWI and ESWD channels will be maintained to prevent excessive deposition of sediment. The staff thus considers this issue resolved.

2.4.14 Technical Specifications and Emergency Operation Requirement

In Section 2.4.14 of the SER, the staff stated that a Technical Specification will be required to ensure that watertight or airtight doors, necessary to prevent floodwaters from entering safety-related buildings, are normally in a closed position. As discussed in Section 2.4.2.2 of this supplement, this requirement is not necessary because the exposed exterior doors are normally closed and alarm when opened, and are tornado-type doors with seals to prevent water entry.

The staff also stated in Section 2.4.14 of the SER that a program to monitor sediment buildup in channels that convey emergency shutdown cooling water will be included in the plant Technical Specifications. As discussed above, this monitoring program has now been provided by the applicant and found acceptable by the staff.

## 2.5 Geology and Seismology

### 2.5.6 Embankments, Dams, and Channels

#### 2.5.6.7 Instrumentation

In Section 2.5.6.7 of the SER, the staff stated that the applicant had committed to inspect the main dam, auxiliary dam, and the auxiliary separating dike in accordance with RG 1.127, Revision 1. However, the staff required that the applicant's compliance with this regulatory guide be included in the plant Technical Specifications.

The applicant, in Technical Specification 6.8.4.f, has complied with the staff's requirement. Thus, the staff considers this issue resolved.

# 3 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

## 3.2 Classification of Structures, Systems, and Components

### 3.2.2 System Quality Group Classification

As was noted in the SER, staff acceptance of the quality group classification of systems and components that perform a safety function was contingent upon the applicant revising appropriate pages of FSAR Table 3.2.1-1.

The staff reviewed the revised pages of Table 3.2.1-1 in Amendment 26 and they are acceptable. The staff concludes that the quality group classification of systems and components in FSAR Table 3.2.1-1 is in conformance with the guidance in Regulatory Guide (RG) 1.26 and provides assurance that component quality is commensurate with the importance of the safety function of these systems and components and constitutes an acceptable basis for satisfying the requirements of General Design Criterion (GDC) 1 and is, therefore, acceptable. This resolves Confirmatory Issue 2.

## 3.5 Missile Protection

### 3.5.1 Missile Selection and Description

#### 3.5.1.3 Turbine Missiles

SER Section 3.5.1.3 contained a recommendation for a license condition. This license condition would require that the applicant (1) submit for NRC approval, within 3 years of obtaining an operating license, a turbine system maintenance program based on the manufacturer's calculations of missile generation probabilities and NRC guidelines or (2) volumetrically inspect all low-pressure turbine rotors at the second refueling outage and at every other (alternate) refueling outage thereafter until some other maintenance program is approved by the staff.

By letter dated May 15, 1986, the applicant provided information regarding its turbine system maintenance program. This letter provides a commitment to follow an inspection program that is based on the recommendations of Westinghouse (the manufacturer) for low-pressure turbine rotor inspection intervals and procedural guidelines. The staff has previously accepted the Westinghouse procedure for estimating turbine failure probabilities. This procedure is used to determine inspection intervals. The administrative controls section of the Shearon Harris Technical Specifications also states that the turbine inspection program will be based on the vendor recommendations.

The applicant has satisfied the provisions of the SER that would have been contained in a license condition, and, therefore, License Condition 1 is no longer required.

Turbine Steam Valve Maintenance

The turbine steam valve maintenance and surveillance requirements (License Condition 2) were superseded by the testing and surveillance requirements contained in Westinghouse (W) Standard Technical Specifications (STS) Section 4.3.4.2. The applicant is required to complete surveillances of turbine steam valves in accordance with the Shearon Harris TS Section 4.3.4.2 which incorporates the W STS. On the basis of TS required surveillances, a separate turbine steam valve surveillance program in the form of a license condition is not required. Therefore, License Condition 2 is deleted.

## 3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping

### 3.6.1 Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment

By letters dated September 23, 1985; June 3, 1986; and September 19 and 23, 1986, the applicant provided information to resolve the issue of main steamline break (MSLB) outside containment (in the steam tunnel) with superheated steam blowdown. The steam tunnel, a large room adjacent to the steamline containment penetrations, houses the main steamline isolation valves and steam header. This room is vented to the atmosphere and is cooled by two safety-grade 40,000 cfm ventilation fans.

The applicant analyzed a spectrum of break sizes (1.4 $ft^2$, 0.86 $ft^2$, 0.5 $ft^2$, and 0.1 $ft^2$) with and without auxiliary feedwater isolation, in the steam tunnel. The computer code COMPARE was used for the analysis of compartment temperature response and component surface temperatures. Of concern are the NAMCO limit switch and the ASCO solenoid valve. Mass and energy release data for a typical Westinghouse plant, modified to account for the automatic isolation of auxiliary feedwater, were used. The heat transfer coefficient was conservatively assumed to be infinite during the steam condensing mode, which means that component surface temperatures reach the saturation temperature essentially at the time of the break. Subsequent to this, a forced convection heat transfer coefficient (calculated as a step function with time, based on the flow velocity) was used. The methodologies used in calculating the compartment temperature and component thermal responses are considered by the staff to be conservative and, therefore, acceptable.

The peak calculated surface temperature of the NAMCO switch is within its equipment qualification temperature limit of 340°F, for all break sizes analyzed, except for the case of a 1.4 $ft^2$ break without auxiliary feedwater (AFW) isolation. This is acceptable because the Shearon Harris design includes automatic AFW isolation capability, for this case, the peak surface temperature of the NAMCO switch is calculated to be 287°F, well below the qualification temperature limit.

For a small break, between 0.5 $ft^2$ and 0.1 $ft^2$, the applicant's analysis shows that the NAMCO switch surface temperature decreases with decreasing break size, assuming no AFW isolation. The blowdown data show, however, that isolation of AFW will occur, but progressively later in the transient as the break size decreases, until, for a 0.1-$ft^2$ break, AFW isolation will not occur. However, because postulated breaks between 0.5 and 0.1 $ft^2$ were not analyzed, it is not clear whether the component surface temperature will also decrease with AFW isolation following a break. Nevertheless, the peak calculated surface temperature of 316°F for a 0.5-$ft^2$ break with AFW isolation is a conservatively calculated value, and can be reduced by refining the calculation of enthalpy rise during the steam generator dryout period. Therefore, the applicant contends that the 316°F surface temperature is a bounding value for breaks smaller than 0.5 $ft^2$, i.e., the surface temperature for small-break sizes would, with a more refined analysis, actually be lower than 316°F. The staff has reviewed the applicant's arguments, and concurs with the rationale that the surface temperature of the NAMCO switch would remain well below its qualification temperature of 340°F.

The peak surface temperature of the ASCO solenoid valve following an MSLB was found to be higher than its qualification temperature of 346°F. The applicant proposes to cover the valve body with 0.25 inch of insulation, which will reduce the maximum surface temperature from 357°F to 248°F. However, the coil housing of the ASCO solenoid valve cannot be covered with insulation because it is normally energized during operation, which results in internal heat generation.

The peak calculated surface temperature of the ASCO coil housing, following an MSLB and including internal heat generation, is 396°F. The staff finds it acceptable to use this temperature value in evaluating the environmental qualification of the ASCO valve even though it is higher than the test environment temperature of 346°F.

Using the same source of internal heat generation as that mentioned above, the applicant attempted to calculate what the valve surface temperature must have been during exposure to the 346°F test environment. The applicant calculated a valve surface temperature of 411°F, and then proposed to use it as the qualification temperature limit. The staff does not agree with this approach since it may not be conservative for determining an elevated qualification temperature limit. The staff recommended that additional test data should be provided to justify a higher qualification temperature than the one established by the test environment. By letter dated September 26, 1986, the applicant referenced ASCO Test Report No. AQR-67368, Revision 0. The referenced report presents test information which shows that ASCO solenoid valves have been tested to temperatures in excess of 440°F and have remained functional. The staff finds this acceptable.

## 3.8 Design of Seismic Category I Structures

In Section 3.8 of the SER, the staff stated that it would review the results of the containment pressure tests. The staff has reviewed the applicant's submittals (January 26 and May 29, 1986) on the ultimate strength capacity of the containment building. The first submittal provides the results of calculations that predict the deformations that will occur when the containment building is subjected to an internal pressure of 1.15 times that of the design pressure. The second submittal provides the results of the structural integrity test conducted February 21-27, 1986, and includes a discussion of the comparison of the actual versus expected analytical results. This information was provided to address SER Confirmatory Issue 8.

The staff finds that the applicant has performed the prediction evaluation and structural integrity test for the containment building utilizing acceptable engineering techniques and criteria that are in agreement with Regulatory Guide (RG) 1.18. The staff considers Confirmatory Issue 8 resolved.

## 3.9 Mechanical Systems and Components

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

#### 3.9.3.2 Design and Installation of Pressure Relief Devices

As required by NUREG-0737, "Clarification of TMI Action Plan Requirements," Item II.D.1, all pressurized-water reactor (PWR) plant licensees and applicants are required to demonstrate that their pressurizer safety valves (SVs), power-operated relief valves (PORVs), PORV block valves, and all associated discharge piping will function adequately under conditions predicted for design-basis transients and accidents. In response to this requirement, the Electric Power Research Institute (EPRI), on behalf of the PWR Owners Group, has completed a full-scale valve-testing program and the Owners Group has submitted these test results to the NRC. Additionally, each PWR plant applicant for an operating license (OL) was required to submit a report by the time fuel was loaded which would demonstrate the operability of these valves and the associated piping.

By letters dated June 28, 1984; June 6, 1986; and July 3, 1986, the applicant responded to this requirement with submittals that contain information from the Electric Power Research Institute (EPRI) valve test program results which apply to Shearon Harris Unit 1. The submittals also state that the safety and relief valve discharge piping and supports are being modified to ensure functionability.

The staff has not completed a detailed review of the applicant's submittals; however, on the basis of a preliminary review, the staff finds that the general approach of using the EPRI test results to demonstrate operability of the safety valves, PORVs, and PORV block valves is acceptable. The applicant's submittal notes that Shearon Harris Unit 1 utilizes safety valves, PORVs, and PORV block valves of the same size and model that performed satisfactorily for test sequences considered representative or that bound conditions to which the valves could be exposed.

In summary, on the basis of preliminary review, the staff has concluded that the applicant's general approach to responding to this TMI item is acceptable and provides adequate assurance that the Shearon Harris Unit 1 reactor coolant system overpressure protection systems can adequately perform their intended functions for the period during which the staff completes its detailed review. If the detailed review reveals that modifications or adjustments to safety valves, PORVs, PORV block valves, or associated piping are needed to ensure that all intended design margins are present, the staff will require that the applicant make appropriate modifications.

### 3.9.6 Inservice Testing of Pumps and Valves

By letter dated January 27, 1986, the applicant submitted a program for the inservice testing (IST) of pumps and valves. This submittal was reviewed by the staff and was the subject of a working meeting with the applicant on August 5 and 6, 1986. On the basis of staff comments during that meeting, the applicant submitted a revised IST program by letter dated September 16, 1986. This revision superseded the previous submittal in its entirety and included changes resulting from discussions during the August 5 and 6 meeting.

The applicant's IST program is required by 10 CFR 50.55a(g) to comply with the ASME Boiler and Pressure Vessel Code, Section XI, 1983 Edition with addenda through Summer 1983. Pursuant to 10 CFR 50.55a(g)(5), the applicant has requested relief from certain ASME Code testing requirements for specific pumps and valves where the Code requirements are impractical within the limits of design, geometry, and system safety. The applicant's request for relief includes an explanation and justification for the relief and a proposal for alternative test procedures.

The staff has completed a preliminary review of the Shearon Harris IST program. That program includes both baseline preservice testing and periodic inservice testing. It provides both for functional testing of components in the operating state and for visual inspection to verify proper valve position.

The staff has not yet completed a detailed review of the applicant's submittal. However, the preliminary review indicates that it is impractical within the limitations of design, geometry, and system safety for the applicant to meet certain specific requirements of the ASME Code. Granting of interim relief from those requirements as provided by the regulations will not endanger life, property, or the common defense and security of the public and is in the public interest, giving due consideration to the burden on the applicant that could result if the requirements were imposed. On the basis of experience at similar plants where no significant adverse health and safety effects were found, the staff concludes that the requirements of 10 CFR 50.55a(g)(6)(i) are satisfied.

Therefore, pursuant to 10 CFR 50.55a(g)(6)(i), the relief that the applicant has requested from certain of the pump and valve testing requirements should be granted on an interim basis until no later than the end of the first refueling outage so that a detailed review of the justifications for each request for relief may be completed. If the detailed review results in any request for relief being denied, the applicant will be required to comply with the appropriate Section XI requirements as required by the regulation 10 CFR 50.55a(g). In addition, if the detailed review identifies any pumps or valves which are not categorized as ASME Code Class 1, 2, or 3 but perform a safety function, those pumps and valves will be included in the IST program if they are not currently included.

## 3.10 Seismic and Dynamic Qualification of Safety-Related Mechanical and Electrical Equipment

### 3.10.1 Operability Qualification of Mechanical and Electrical Equipment

#### 3.10.1.1 Introduction

A two-step review is performed for each applicant's pump and valve operability assurance program to determine whether its 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 Final Safety Analysis Report (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 preliminary input to the Safety Evaluation Report (SER).

A Pump and Valve Operability Review Team (PVORT), consisting of engineers from the NRC staff and the Idaho National Engineering Laboratory (INEL, EG&G Idaho) conducted the second step, which consisted 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 determined whether the applicant's overall program conforms to the current licensing criteria presented in Section 3.10 of the Standard Review Plan (SRP). Conformance with SRP Section 3.10 criteria is required in order to satisfy the applicable portions of General Design Criteria (GDC) 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50 and 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 applicant's overall pump and valve operability assurance program, (3) a discussion of the confirmatory 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 issues identified in the SER and their status.

3.10.1.2 Discussion

The PVORT reviewed the pump and valve operability assurance information contained 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 five issues which resulted from the Shearon Harris FSAR evaluation appear in the SER and were supplemented by specific comments discussed at a pre-audit meeting held March 21, 1984. In a May 29, 1984, letter, the applicant reported that several of these issues had been adequately resolved. The remaining SER issues were addressed and resolved during the onsite audit.

Table 3.2 summarizes the status of the five SER items. The staff believes that the applicant has clarified its position concerning these items and has committed to 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 NSSS and six 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 applicant maintains in its central files. In addition to reviewing information concerning the selected assemblies, the PVORT reviewed other information concerning the plant's overall equipment qualification program. Included within this broad evaluation were 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 (refer to IE Bulletin 79-15), was reviewed in depth. At the end of the site audit, the PVORT resolved all but one of the specific operability concerns that were identified during the audit. The specific concern was that the 12-inch gate valve 3CC-V165 had been qualified by analysis only. In addition, the applicant was informed of three generic issues for which responses were needed before fuel load. The staff identified these three generic issues as: (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; and (3) approximately 10 to 15% of all pumps and valves important to safety have not been completely qualified and installed. These concerns and issues were determined to be confirmatory in nature at the end of the site audit and formed the basis for the discussion presented in Section 3.10.1.3.

Following the site audit, the applicant submitted a letter, dated January 27, 1986, which resolved the one specific issue and partially resolved the generic issues. The three generic issues were completely resolved by information provided in FSAR Amendment 33 and letters dated August 1 and 29, 1986.

A new generic open issue arose from post-audit discussions with the applicant on February 21 and April 11, 1986. The open issue was that the qualification of some safety-related equipment did not appear to be linked to any test data. In letters dated June 6, June 12 and August 29, 1986, and in a meeting held on September 17, 1986, the applicant provided information which resolved the generic issue in a satisfactory manner.

3.10.1.3 Operability Issues

The PVORT's evaluation of the Shearon Harris Pump and Valve Operability Assurance Program identified several operability issues, all of which have been satisfactorily resolved by the applicant. A restatement of the identified issues and the manner by which each was addressed is presented below and in Table 3.1.

(2) Generic Confirmatory Issues

(a) 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 applicant should confirm that all active valves are correctly identified in the FSAR.

Resolution

Information was provided by the applicant in FSAR Amendment 33. This issue is closed.

(b) Issue

At the time of the audit, most construction tests had already been completed. However, the hot functional tests were scheduled to commence later in November 1985. The applicant shall confirm that all preservice tests that are required before fuel load have been completed.

Resolution

In a letter dated August 1, 1986, the applicant indicated that the preservice tests of all active pumps and valves are expected to be completed before fuel load. The applicant included a schedule of construction and preservice test activities that will not be completed before fuel load; these activities, however, do not involve any active pumps and valves. The applicant's commitment regarding the completion of the preservice testing is acceptable to the staff. This issue is closed.

(c) Issue

At the time of the audit, approximately 10 to 15% of all pumps and valves important to safety had not been qualified. The applicant shall confirm that all pumps and valves important to safety are properly qualified and installed. In addition, the applicant 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 loss-of-coolant accident (LOCA) (hydrodynamic loads) or as-built conditions.

Resolution

The applicant has provided satisfactory verification based on a response dated September 25, 1986. This issue is closed.

(3) Specific Confirmatory Issue

The 12-inch Velan gate valve (3CC-V165) was qualified by analysis only. The applicant should provide test data demonstrating the ability of this valve assembly to operate as required under its design load conditions. The applicant 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.

Resolution

In a letter dated January 27, 1986, the applicant provided analytical confirmation that the valve will experience negligible deformation due to seismic loading. This is satisfactory. This issue is closed.

(4) Generic Open Issue

The applicant was not able to provide qualification test data for Velan valves 12GM32SB and 6GM62FB and Fisher valve 18BM32. The staff's concern is that the qualification of other safety-related equipment might not be linked to any test data at all. In order to resolve this issue, the applicant shall resolve the issues identified below before fuel load.

(a) Issue

The applicant shall identify all active NSSS and BOP valves that have been qualified by analysis only.

Resolution

In letters dated June 6 and 12, 1986, as well as in a meeting on September 17, 1986, the applicant provided draft copies of FSAR Tables 3.9.3-13 and -14 which identified the NSSS and BOP valves qualified by analysis only, and provided additional clarification that for a sampling of valves a linkage between qualification by analysis and qualification by test is present. This is satisfactory. This issue is closed.

(b) Issue

On the basis of a representative sampling of the list identified in item a above, the applicant shall demonstrate that the qualification methods used are conservative. For each valve selected, the applicant shall provide the end loads and accelerations calculated from the loads verification analysis. The applicant shall compare these as-built loads with the levels for which the equipment is qualified. In addition the applicant shall indicate to what extent the qualification test data of other valves used at Shearon Harris can be linked to the representative sampling. The applicant shall describe the basis for assessing similarity.

Resolution

In a letter dated June 6, 1986, the applicant showed that for a representative sampling of ten valves the as-built loads are less than the acceleration levels for which the valves have been analyzed. The pipe stress analysis has inherent conservatisms which include: enveloped response spectra, low damping values, peak spreading of response spectra, absolute summation of closely spaced modes, and the simultaneous occurrence of spectral peaks and seismic displacements. The applicant indicated that preoperational, startup, and periodic inservice tests in conjunction with the maintenance and surveillance programs will demonstrate operability readiness throughout the life of the plant.

In a June 12, 1986, letter, the applicant amended FSAR Tables 3.9.3-13 and -14 to indicate that valves qualified by analysis were similar to valves actually tested. Additional clarification as discussed in item a above was provided at a technical information meeting on September 17, 1986. This issue is closed.

(c) Issue

During the April 11, 1986 meeting the applicant committed to qualify the Fisher 18-inch butterfly valve by testing before fuel load. A copy of the test results shall be submitted for staff review.

Resolution

On May 8, 1986, the staff observed tests of the Fisher 18-inch butterfly valve performed at Wyle Laboratory in Huntsville, Alabama. The applicant submitted a copy of the test results on July 28, 1986. This valve was satisfactorily qualified; therefore, this issue is closed.

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 applicant throughout the audit, and (3) the resolution of the SER items, the staff concludes that an acceptable 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. The staff concludes that

Shearon Harris has 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 as well as Appendix B to 10 CFR 50.

### 3.10.2 Seismic and Dynamic Qualification of Electrical and Mechanical Equipment

Evaluation of the applicant's 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 the Standard Review Plan (SRP) Section 3.10, and its ancillary documents, Regulatory Guides (RGs) 1.61, 1.89, 1.92, 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 General Design Criteria (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 staff and the Idaho National Engineering Laboratory (INEL, EG&G Idaho).

The SQRT reviewed the equipment dynamic qualification information contained in the Final Safety Analyses Report (FSAR) Sections 3.9.2 and 3.10 and made a plant site visit from December 3 through December 6, 1985. The purpose of the site visit 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 nuclear steam supply system (NSSS) and balance of plant (BOP) scopes, was audited. The plant-site audit started with field observations of the final equipment configuration and installation. This was followed by a review of the corresponding design specifications and of test and/or analysis documents which the applicant maintains in its central files. Observing the field installation of the equipment is necessary to verify and validate equipment modeling employed in the qualification program. In addition to the document reviews and equipment inspections, the applicant presented details of maintenance, startup testing, and in-service inspection procedures.

The audit identified both plant generic and equipment-specific concerns relating to the seismic and dynamic qualification program. A summary of all issues is given in SER Supplement 3 (SSER 3), Section 3.10. After the audit, the applicant conducted further investigations through tests and analyses. On the basis of the results of its investigations, responses to the issues of concern were provided in the attachment to its letter dated August 29, 1986. A summary of the resolution and status of the issues identified in SSER 3 is provided in the following sections.

### 3.10.2.1 Generic Items

Inadequate Clearance Between Cabinets

The applicant indicated that the program to address this issue is complete and the problem is resolved. The resolution in each case required one or a combination of the following three steps. They are: (1) the actual separation was analyzed and found adequate, (2) adjacent cabinets were coupled to preclude impact, and (3) cabinet deflections were restricted by anchorage modification. This issue is now closed.

Limited-Life Components

The applicant indicated that the life-span evaluation of non-metallic parts was performed for components located in harsh environments only. There is no similar evaluation of components located in mild environments. The applicant indicated that these latter components would be handled through the maintenance and surveillance (M/S) program. It was not clear how the M/S program would be able to handle a limited life component if its life-span is not established, either by the vendor or by the applicant, and incorporated into the program.

In a letter dated October 6, 1986, the applicant committed to the following:

(1) a periodic maintenance, inspection, and replacement program based on sound engineering practice and recommendations of the equipment manufacturer which is updated as required by the results of an equipment surveillance program

(2) a periodic testing program to verify operability of safety-related equipment within its performance specification requirements (system level testing of the type typically required by the plant Technical Specifications may be used)

(3) an equipment surveillance program which includes periodic inspections, analysis of equipment and component failures, and a review of the results of preventive maintenance and periodic testing programs

In addition, the applicant will review procurement specifications of safety equipment such as remote panels, valves, and valve operators to determine if the procured equipment was specified by the vendor as less than 40-year life. Depending on the outcome of the review, the following courses of action will be taken:

(1) Life is at least equal to 40 years--no further action is necessary.

(2) Life is specified by the vendor in the procurement documents--action is necessary to incorporate the specified life in the maintenance and surveillance program.

(3) Life is not specified by the vendor and the vendor was not requested to specify the qualified life--action is required to elicit information from either a vendor or a suitable source and to incorporate an appropriate replacement frequency into the maintenance and surveillance program.

The applicant will fully document this activity and maintain the documentation for audit by the staff. This resolution is acceptable to the staff and this issue is closed.

Flexible Valves

The applicant commenced an evaluation program which has been satisfactorily completed. The applicant provided a table showing comparisons of natural frequencies based on analyses and tests. The comparisons are quite close. This issue was adequately addressed. It is now closed.

Overall Completion of Qualification

On an overall program basis, the applicant, according to its letter no. NLS-86-349 dated September 25, 1986, confirmed that the seismic qualification of all safety related equipment was completed including the verification of the as-built piping system with respect to pumps and valves. This issue is closed.

3.10.2.2 Equipment-Specific Items

Complete Qualification of Control Room Cabinet

On the basis of the letter dated August 29, 1986, the applicant has completed the qualification of the control room cabinet including its internals. This issue is now closed.

3.10.2.3 Summary and Conclusion

On the basis of the Seismic Qualification Review Team (SQRT) site audit and the submittals from the applicant, the staff concludes that an appropriate seismic and dynamic qualification program has been defined and implemented including the issue on replacement of limited-life components as discussed in Section 3.10.2.1 under "Limited-Life Components."

The staff concludes that the applicant's seismic qualification program for safety-related equipment at Shearon Harris Unit 1 satisfies the applicable portions of General Design Criteria 1, 2, 4, 14, and 30 of Appendix A as well as Appendix B to 10 CFR 50 and Appendix A to 10 CFR 100.

## 3.11 Environmental Qualification of Electrical Equipment

### 3.11.1 Introduction

Equipment that is used to perform a necessary safety function must be demonstrated to be capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement - which is embodied in GDC 1 and 4 of Appendix A to 10 CFR 50 and Sections III, XI, and XVII of Appendix B to 10 CFR 50 - is applicable to equipment located inside as well as outside containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment have been provided in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"; NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment" (which supplements the Institute of Electrical and Electronics Engineers (IEEE) Standard 323); and various NRC regulatory guides and industry standards.

### 3.11.2 Background

NUREG-0588 was issued in December 1979 to promote a more orderly and systematic implementation of equipment qualification programs by industry and to provide guidance to the NRC staff for use in ongoing licensing reviews. The positions contained in that report provide guidance on (1) how to establish environmental service conditions, (2) how to select methods that are considered appropriate for qualifying equipment in different areas of the plant, and (3) other areas such as margin, aging, and documentation. In February 1980, the NRC asked certain near-term operating license (OL) applicants to review and evaluate the environmental qualification documentation for each item of safety-related electrical equipment and to identify the degree to which their qualification programs were in compliance with the staff positions discussed in NUREG-0588.

IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," issued by the NRC Office of Inspection and Enforcement (IE) on January 14, 1980, and its supplements dated February 29, September 30, and October 24, 1980, established environmental qualification requirements for operating reactors. This bulletin and its supplements were provided to OL applicants for consideration in their reviews.

A final rule on environmental qualification of electrical equipment important to safety for nuclear power plants became effective on February 22, 1983. This rule, 10 CFR 50.49, specifies the requirements to be met for demonstrating the environmental qualification of electrical equipment important to safety located in a harsh environment. In conformance with 10 CFR 50.49, electrical equipment for Shearon Harris Nuclear Power Plant may be qualified according to the criteria specified in Category II of NUREG-0588.

The qualification requirements for mechanical equipment are principally contained in Appendices A and B of 10 CFR 50. The qualification methods defined in NUREG-0588 can also be applied to mechanical equipment.

To document the degree to which the environmental qualification program complies with the NRC environmental qualification requirements and criteria, the applicant provided equipment qualification information by letters dated August 27, September 11, and December 23, 1985, and January 23, January 31, and March 5, 1986, to supplement the information in FSAR Section 3.11. The staff has reviewed the adequacy of the Shearon Harris environmental qualification program for electrical equipment important to safety as defined in 10 CFR 50.49 and the program for safety-related mechanical equipment. The scope of this report includes an evaluation of (1) the completeness of the list of systems and equipment to be qualified, (2) the criteria they must meet, (3) the environments in which they must function, and (4) the qualification documentation for the equipment. It is limited to electrical equipment important to safety within the scope of 10 CFR 50.49 and safety-related mechanical equipment.

### 3.11.3 Staff Evaluation

The staff evaluation included an onsite examination of equipment, an audit of qualification documentation, and a review of the applicant's submittals for completeness and acceptability of systems and components, qualification methods, and accident environments. The criteria described in SRP Section 3.11 (NUREG-0800) and in NUREG-0588, Category II, and the requirements in 10 CFR 50.49 form the bases for the staff evaluation.

The staff performed an audit of the applicant's qualification documentation and installed electrical equipment on November 19, 20, and 21, 1985. The audit consisted of a review of nine files containing information regarding equipment qualification. The staff's findings from the audit are discussed in Section 3.11.4 of this report.

3.11.3.1 Completeness of Equipment Important to Safety

10 CFR 50.49 identifies three categories of electrical equipment that must be qualified in accordance with the provisions of the rule. These are

(1) safety-related electrical equipment (equipment relied on to remain functional during and following design-basis events)

(2) non-safety-related electrical equipment whose failure under the postulated environmental conditions could prevent satisfactory accomplishment of the safety functions by the safety-related equipment

(3) certain postaccident monitoring equipment (RG 1.97, Category 1 and 2 postaccident monitoring equipment)

The applicant has provided information addressing compliance with this requirement of 10 CFR 50.49.

The systems identified by the applicant for the environmental qualification program as being required to function to mitigate the consequences of loss-of-coolant accidents (LOCAs) or high-energy-line breaks (HELBs) that have components located in a harsh environment were compared with FSAR Table 3.2-1, "Equipment Classification." The omission of systems from the harsh environment program was adequately justified by the applicant. The systems identified as performing the safety functions of emergency reactor shutdown, containment isolation, reactor core cooling, containment heat removal, reactor heat removal, and effluent control follow:

AC power distribution
Auxiliary feedwater
Cable & raceway
Chemical & volume control
Chlorine leak detection
Containment combustible gas control
Component cooling water
Condensate
Containment cooling
Containment atmosphere purge/makeup
Containment isolation*
Containment spray
Containment vacuum relief
Control boards & panels (instrumentation)
Control room HVAC
DC power distribution
Essential services chilled water
Excore neutron monitoring
Fire protection
Fuel handling building HVAC
Main steam
Miscellaneous drains (instrumentation)
Miscellaneous items

*The containment isolation system consists of safety-related valves, penetrations, and other devices which may be contained in non-safety-related systems.

- Auxiliary feedwater
- Blowdown
- Chemical & volume control
- Component cooling water
- Containment atmosphere purge/makeup
- Containment hydrogen purge/makeup
- Containment penetration
- Containment spray
- Containment vacuum relief
- Feedwater
- Fire protection
- Instrument air
- Main steam
- Miscellaneous drains
- Safety injection
- Sampling
- Service air
- Service water

Radiation monitoring
Containment spray
Reactor coolant
Reactor makeup water
Reactor support/cavity HVAC
Residual heat removal
Safety injection
Service water
Spent fuel pool cooling & cleanup
Waste processing (liquid)
Waste processing (gas)

To demonstrate compliance with 10 CFR 50.49(b)(2) concerning non-safety-related equipment whose failure under postulated accident conditions could prevent the satisfactory accomplishment of safety functions, the applicant referred to compliance with IEEE Std 384-1974 as modified by RG 1.75 to show electrical and physical separation between safety-related and non-safety-related electrical equipment. The staff has reviewed and evaluated the applicant's conformance with RG 1.75 and finds it acceptable from an equipment qualification aspect. The results of the staff review are found in Section 8.4.1 of the SER. The applicant has also conducted a study in response to the concerns addressed by the staff in IE Information Notice 79-22, "Qualification of Control Systems," issued September 19, 1979. The staff found the applicant's response to the concerns addressed in IE Information Notice 79-22, acceptable. The results of the staff review are found in Section 7.7.2 of the SER. On this basis, the staff concludes that the applicant's conformance to 10 CFR 50.49(b)(2) is acceptable.

10 CFR 50.49(b)(3) requires that all installed RG 1.97, Category 1 and 2 instrumentation located in a harsh environment be included in the equipment qualification program unless adequate justification is provided. The applicant has indicated that all such equipment is included in the qualification program; however, in addressing conformance with RG 1.97, the applicant has identified a number of alternative methods of meeting the intent of RG 1.97. The staff has determined the acceptability of these alternative methods as part of its review for conformance with RG 1.97, and reported its findings in Section 13.3.5 of SER Supplement 3.

### 3.11.3.2 Qualification Methods

#### 3.11.3.2.1 Electrical Equipment in a Harsh Environment

Detailed criteria for qualifying safety-related electrical equipment in a harsh environment are defined in NUREG-0588. These criteria are also applicable to the other equipment important to safety defined in 10 CFR 50.49.

The staff has reviewed the methods used by the applicant to demonstrate qualification to ensure that they are in compliance with NUREG-0588.

3.11.3.2.2 Safety-Related Mechanical Equipment in a Harsh Environment

Although there are no detailed requirements for mechanical equipment, GDC 1, "Quality Standards and Records," and GDC 4, "Environmental and Missile Design Bases," and Appendix B to 10 CFR 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" (Sections III, "Design Control," and XVII, "Quality Assurance Records"), contain the following requirements related to equipment qualifications:

- Components shall be designed to be compatible with the postulated environmental conditions, including those associated with LOCAs.

- Measures shall be established for the selection and review for suitability of application of materials, parts, and equipment that are essential to safety-related functions.

- Design control measures shall be established for verifying the adequacy of design.

- Equipment qualification records shall be maintained and shall include the results of tests and materials analyses.

The results of the safety-related mechanical equipment qualification program have been submitted to the staff for review. In addition, qualification documentation for three items of safety-related mechanical equipment has been submitted by the applicant and has been reviewed by the staff. The staff review has verified that the requirements for environmental qualification of safety-related mechanical equipment have been adequately addressed.

3.11.3.3 Service Conditions

NUREG-0588 defines the methods to be used for determining the environmental conditions associated with LOCAs or HELBs, inside or outside containment. The review and evaluation of the adequacy of these environmental conditions are described below. The staff has reviewed the qualification documentation to ensure that the qualification conditions envelope the environmental conditions established by the applicant.

3.11.3.3.1 Temperature, Pressure, and Humidity Conditions Inside Containment

The applicant provided the LOCA/main steamline break (MSLB) profiles used for equipment qualification program submittals. The peak values shown on these profiles are as follows:

Maximum temperature: 380°F
Maximum pressure: 41 psig
Humidity: 100% (steam)

The staff has reviewed these profiles and finds them acceptable for use in equipment qualification; that is, there is reasonable assurance that the actual pressures and temperatures will not exceed these profiles anywhere within the specified environmental zone (except in the break zone).

3.11.3.3.2 Temperature, Pressure, and Humidity Conditions Outside Primary Containment

The applicant has provided the temperature, pressure, and humidity conditions associated with HELBs outside containment. The criteria used to define the location of HELBs are described in FSAR Section 3.6. The staff has used a screening criterion of saturation temperature at the calculated pressure to verify that the peak temperatures identified by the applicant are acceptable.

The effect of superheated steam on equipment qualification has been addressed by the applicant and is discussed in Section 3.6.1 of this supplement.

3.11.3.3.3 Submergence

Flood levels for various areas have been calculated; the maximum flood level will be at the 228.3-foot elevation inside containment. The effects of flooding on equipment have been evaluated to ensure that safe shutdown can be achieved. The applicant has taken appropriate corrective action to relocate or qualify all affected equipment.

3.11.3.3.4 Chemical Spray

A chemical spray inside containment may be used to mitigate the effects of an accident. The applicant has included this parameter in the evaluation of equipment located inside containment.

3.11.3.3.5 Aging

The aging program requirements for electrical equipment at Shearon Harris are defined in Category II of NUREG-0588. Category II delineates two aging programs. Valve operators committed to IEEE Std 382-1972 and motors committed to IEEE Std 334-1971 must meet the Category I guidelines in NUREG-0588. This requires that all known degrading influences be considered and included in the aging program. Justification for excluding pre-aging of equipment in type testing must be established on the basis of equipment design and application of state-of-the-art aging techniques. A qualified life is to be established for each equipment item. For other equipment, the qualification program should address aging to the extent that equipment composed (in part) of materials susceptible to the effects of aging should be identified and a schedule for periodically replacing the equipment or the material should be established.

In addition to the above, a maintenance/surveillance program must be implemented to identify and prevent significant age-related degradation of electrical and mechanical equipment. In the FSAR, the applicant committed to follow the recommendations in RG 1.33, Revision 2, "Quality Assurance Program Requirements (Operation)," which endorses American Nuclear Society/American National Standards Institute Standard ANS 3.2/ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." This standard defines the scope and content of a maintenance/surveillance program for safety-related equipment. Provisions for preventing or detecting age-related degradation in safety-grade equipment are specified and include (1) utilizing experience with similar equipment, (2) revising and updating the program as experience is gained with the equipment during the life of the plant, (3) reviewing and evaluating malfunctioning equipment and obtaining adequate replacement components, and (4) establishing surveillance tests and inspections based on reliability analyses, frequency and type of service, or age of the items, as appropriate.

The applicant has described a program that incorporates the above guidelines and has stated that the maintenance/surveillance program will be implemented at the time of fuel load. The applicant has provided a description of the specific program that will be used to detect unanticipated, age-related degradation of electrical cables inside containment. The program as described above is acceptable for the purposes of the environmental qualification program.

3.11.3.3.6 Radiation (Inside and Outside Containment)

The applicant has provided values of the radiation levels postulated to exist following a loss-of-coolant accident (LOCA). The accident radiation environments in primary containment have been defined according to NUREG-0588. For this review, the staff has assumed that the values provided have been determined in accordance with the prescribed criteria. The staff review determined that the values to which the equipment is qualified enveloped the requirements identified by the applicant.

The maximum total radiation dose specified by the applicant is $1.1 \times 10^8$ rads gamma inside primary containment. Outside of the containment, values up to $8.1 \times 10^7$ rads gamma were used in the evaluation of equipment. These values are acceptable for use in the qualification of equipment.

3.11.3.4 Outstanding Equipment

For items not having complete qualification documentation, the applicant has provided a commitment for corrective action and a schedule for completion. By letter dated September 19, 1986, the applicant committed to have equipment installed as environmentally qualified before declaring it operational. The staff considers this item closed.

3.11.4 Environmental Qualification Audit

The staff, with assistance from the Idaho National Engineering Laboratory (INEL), audited the applicant's qualification files on November 19, 20, and 21, 1985. The purpose of the audit was to verify the bases of the information submitted by the applicant. Nine equipment qualification files, representing approximately 10% of the equipment items in the equipment qualification program, were selected for audit.

The equipment items selected for audit were:

(1) Anaconda Instrument Cable Type NSIS (file 6.2 BOP)
(2) Anaconda Switchboard Cable Type NSIS (file 6.11 NSSS)
(3) Conax Seal Assembly Model ECSA
(4) BIW Triaxial Cable CSPE/Tefzel RG11-U
(5) Gould Pressure Transmitter Model PG 3200-200
(6) Rockbestos Cable RSS6-104, RSS6-105, RSS6-108

(7) Limitorque Valve Operator SMB-000
(8) Rosemount Transmitter Model 1153 Series B
(9) Westinghouse Penetrations Conductor Modules WX-33XXX

These files were reviewed to determine if qualification had been demonstrated on the basis of the documents contained in the files.

A number of concerns were identified to the applicant during the audit. These consisted of discrepancies within the Component Evaluation Sheets, the use, in part, of the transient portion of the test profile to demonstrate postaccident operating time, and review of qualification test results versus plant-specific requirements.

All these concerns have been resolved and no issues remain.

As part of the audit, the equipment as actually installed was inspected during a plant walkdown. The purpose of the walkdown was to verify that the manufacturer, model number, location, and installation are consistent with the qualification documents. No discrepancies were discovered.

### 3.11.5 Conclusions

The staff has reviewed the program at Shearon Harris for the environmental qualification of electrical equipment important to safety and safety-related mechanical equipment. The purpose of the review was to determine the adequacy of the program, including the scope of the qualification program, the environmental conditions resulting from design-basis accidents, and the methods used to demonstrate qualification.

On the basis of the results of its review, the staff concludes that the applicant has demonstrated full conformance with the requirements for environmental qualification as detailed in 10 CFR 50.49, the relevant parts of GDC 1 and 4, and Sections III, XI, and XVII of Appendix B to 10 CFR 50, and with the criteria specified in NUREG-0588.

Table 3.1 Summary of PVORT audit for the Shearon Harris Nuclear Power Plant

| Plant ID number | Description | Component function | Findings | Resolutions | Status | Remarks |
|---|---|---|---|---|---|---|
| 3CE-V43SAB-1 (BOP) | Auxiliary feed pump suction check valve (TRW Mission Industrial 8-inch wafer check) | Valve is normally closed. Valve opens when AFW is supplied by steam-driven feed pump. | -- | -- | Closed | Specific concerns were resolved during the audit. |
| 3CT-V885B-1 (BOP) | Containment spray additive valve (Yarway 2-inch 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 the audit. |
| 3SW-B1SA-1 (BOP) | Emergency service water intake screening structure isolation valve (Jamesbury 30-inch 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 the audit. |
| 3AF-F3SA-1 (BOP) | AFW pump discharge flow control valve (Masoneilan 3-inch electrohydraulic globe) | Valve is normally open. Valve closes to isolate SG FW header in event of rupture of FW header or main steam header. Valve fails open. | -- | -- | Closed | Specific concerns were resolved during the audit. |
| PIA-SA (BOP) | ESW pump (Hayward Tyler 30 VSN vertical centrifugal 21,500 gpm) | Pump is normally at standby. Pump starts automatically on loss of offsite power or upon SI signal. Pump supplies cooling water to equipment required for safe plant shutdown. | -- | -- | Closed | Specific concerns were resolved during the audit. |
| 2MS-V95A (BOP) | Auxiliary feed pump turbine steam supply isolation valve (Anchor Darling 6-inch motor-operated flex-wedge gate) | Valve is normally closed. Valve opens for operation of AFW pump turbine upon initiation signal. Valve fails as is. | -- | -- | Closed | Specific concerns were resolved during the audit. |
| 3CC-V165 SA (NSSS) | CCW to RHR HX isolation valve (Velan 12-inch 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. | a | b | Closed | Valve was qualified by analysis only. Applicant shall provide test data demonstrating the ability of this valve assembly to operate as required under its design load conditions. This issue was resolved by the applicant's letter dated January 27, 1986. |

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-inch 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 the audit. |
| APCC-1C-SAB (NSSS) | CCW pump (Pacific DSK centrifugal 11,000 gpm) | Pump is normally operating. Pump supplies CCW to various NSSS heat exchangers. | -- | -- | Closed | Specific concerns were resolved during the audit. |
| 2SI-V579A (NSSS) | Cold-leg injection and RHR return line isolation valve (Westinghouse 10-inch motor-operated gate) | Valve is normally open in discharge line from RHR pump downstream of RHX 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 the audit. |
| -- | All pumps and valves important to safety | Operate as required during the life of the plant under normal and accident conditions | d,e,f,g | b | Closed | Issue "d" was resolved by FSAR Amendment 33. Issue "e" was resolved by letter dated August 1, 1986. Issue "f" was resolved by letter dated August 29, 1986. Issue "g" was resolved by letters dated June 6 and 12, 1986, by a submittal dated July 29, 1986, and by a meeting held September 17, 1986. |

a. (SPECIFIC ISSUE) The applicant did not provide any test data to qualify the valve. The applicant shall provide test data demonstrating the ability of this valve assembly to operate as required under its design load conditions.

b. 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.

c. The qualification status will be "closed" upon resolution of the specific and generic confirmatory issues.

d. (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 applicant shall confirm that all active valves are correctly identified in the FSAR.

e. (GENERIC ISSUE) Some preservice tests required to be completed before fuel load have not yet been performed. The applicant shall confirm that all appropriate preservice tests have been completed before fuel load.

f. (GENERIC ISSUE) Some pumps and valves important to safety have not been completely qualified and installed. The applicant shall confirm that all pumps and valves important to safety are completely qualified and installed before fuel load. Also, the applicant 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).

g. (GENERIC ISSUE) The qualification of some safety-related equipment does not appear to be linked to any test data. The applicant shall (1) identify all safety-related pumps and valves qualified by analysis only; (2) demonstrate that the method of qualification is conservative for a representative sampling of valves qualified by analysis only, and (3) qualify the Fisher 18-inch butterfly valve by testing.

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

| SER items[a] | Finding/ Resolution | Status |
|---|---|---|
| (1) All active safety-related valves, including those valves smaller than 2 inches in size, should be included in the Shearon Harris pump and valve operability program. | Satisfactory | Closed[b] |
| (2) Clarification of how aging was incorporated into the qualification process should be contained in the FSAR. In addition, the applicant should commit to establish a maintenance and surveillance program to maintain equipment in a qualified status throughout the life of the plant. The criteria for the maintenance and surveillance program should be contained in the FSAR. A license condition has been imposed to resolve this issue. | Satisfactory | Closed[b] |
| (3) The FSAR should be amended to clearly show the loads and conditions considered in the qualification of safety-related pumps and valves. | Satisfactory | Closed[c] |
| (4) 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. In addition, the applicant's position with respect to RG 1.148 must be indicated in the FSAR. | Satisfactory | Closed[c] |
| (5) The FSAR should be amended to show the extent to which operational testing is being used to meet the requirements of SRP Section 3.10. The extent to which operational testing is performed at full flow and temperature conditions should be shown. | Satisfactory | Closed[c] |

a. The Shearon Harris SER items for pump and valve operability assurance were identified in a safety evaluation dated October 6, 1983, and were supplemented by specific comments discussed at a preaudit meeting held March 21, 1984.

b. This item was adequately resolved based on information submitted by the applicant in a letter (NLS-84-201) from S. R. Zimmerman, CP&L, to H. R. Denton Director, NRC, May 29, 1984.

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

# 4 REACTOR

## 4.3 Nuclear Design

### 4.3.2 Design Description

Power Distribution

The generic peaking factor for Westinghouse reactors is 2.32. Use of the standard power distribution control procedures (constant axial offset control) justifies that the peaking factor will not exceed 2.32 in normal operation of the power plant. In the SER, concern was expressed that the Shearon Harris peaking factor would have to be appreciably less that 2.32 in order to meet the initial conditions assumed in the loss-of-coolant accident (LOCA) analysis. Justification of how the reactor would be operated to maintain the LOCA peaking factor was identified as Confirmatory Issue 9.

In SER Supplement 3, Confirmatory Issue 9 was resolved by reference to the applicant's commitment to use an excore APDMS (axial power distribution monitoring system), called the excore axial power monitor (ECAPM). In a letter dated August 26, 1986, from S. R. Zimmerman, CP&L, to H. R. Denton, NRC, the applicant presented a LOCA analysis justifying a peaking factor of 2.28. Acceptability of the LOCA analysis is discussed in Section 6.3.5.1 of this supplement. The applicant's analysis justifies the reduction of the peaking factor from 2.32 to 2.28, in part by a slight reduction of the radial peaking factor in the Technical Specifications and the remainder by a plant-specific analysis of the load following maneuvers used in the confirmation of the generic peaking factor of 2.32. The staff considers these measures adequate to ensure that the peaking factor of 2.28 will not be exceeded in normal operation of the power plant. The applicant's earlier commitment to use the ECAPM as described in SER Supplement 3 is, therefore, no longer required and will not be reflected in the Shearon Harris Technical Specifications.

### 4.3.5 Moderator Temperature Coefficient

In a letter to the NRC dated April 23, 1986, the applicant requested a change to the moderator temperature coefficient (MTC) Technical Specification to be issued for Shearon Harris. The request proposes to increase the upper bound of the MTC from 0 to 5 pcm*/°F for power levels below 70% of rated power, ramping down to 0 pcm/°F at full power.

By way of background, cores of this type generally have a slightly positive MTC at beginning of life, hot zero power, all control rods out. The coefficient becomes zero if the boron concentration is reduced by swapping with control rods, going to part power, or building in xenon. What this means is, in order to get the reactor on line, temporary control rod withdrawal limits must be established which keep the MTC zero as a function of power level. Performing

*pcm = percent millirho

calculations to generate the withdrawal limits and the extra care required to observe the limits delays the startup sequence. The staff has approved operation with slightly positive MTCs on numerous occasions in the past. In addition, Shearon Harris has a light (low reactivity worth) control Bank D, which might require deeper insertion than allowed by the insertion limit Technical Specification, which could delay power ascension even further without the proposed change.

The applicant has assessed the impact of a positive MTC on the accident analyses presented in Chapter 15 of the FSAR. Those incidents which were found to be sensitive to positive or near-zero moderator coefficients were reanalyzed. These incidents are limited to transients which cause the reactor coolant temperature to increase. Accidents not reanalyzed included those resulting in excessive heat removal from the reactor coolant system (RCS), for which a large negative moderator coefficient is more limiting, and those for which heatup effects following reactor trip are not sensitive to the moderator coefficient. The staff agrees with the applicant's conclusions about which transients did and which did not require reanalysis.

The transients not reanalyzed are:

- RCCA misalignment/drop
- startup of an inactive reactor coolant loop
- excessive heat removal due to feedwater system malfunctions
- excessive load increase
- spurious actuation of safety injection
- rupture of a main steam pipe
- loss-of-coolant accident (LOCA)
- boron dilution
- loss of normal feedwater, or of offside power
- rupture of a main feedwater pipe
- accidental depressurization of the reactor coolant system.

The incidents reanalyzed, with three exceptions, used a +5 pcm/°F MTC, assumed to remain constant for variations in temperature. This is conservative, since the proposed change will require the coefficient to ramp to zero at full power. Two of the exceptions are the rod ejection and the rod withdrawal from subcritical accidents, for which the computer model cannot accept a constant coefficient. The coefficient decrease which occurred during the transients was less than the proposed change, which is acceptable. The coefficient for the other case, the locked rotor, is discussed below.

The transients reanalyzed and their results are:

(1) Control Rod Bank Withdrawal From a Subcritical Condition

This transient results in an uncontrolled addition of reactivity leading to a power excursion causing a heatup of the moderator and fuel. The time the core is critical before a reactor trip is very short so that the RCS temperature does not increase significantly; hence the effect of a positive MTC is small. The analysis results show a transient average heat flux which does not exceed the steady-state full-power value and an increased core water temperature that remains below the full-power value. The results show that the departure from nucleate boiling ratio (DNBR) remains above 1.3 during the transient.

(2) Uncontrolled Control Rod Bank Assembly Withdrawal at Power

This transient produces a mismatch in steam flow and core power, resulting in an increase in RCS temperature. However, the results show that the nuclear flux and overtemperature $\Delta T$ trips prevent the core minimum DNBR from falling below 1.3 for this transient, which is acceptable.

(3) Loss of Coolant Flow

The most severe loss of flow transient is caused by the simultaneous loss of power to all three reactor coolant pumps. This case was reanalyzed to determine the effect of a positive MTC on the nuclear power transient and the resultant effect on the miniumum DNBR reached during the transient. The minimum DNBR remains above 1.3 during the transient, which is acceptable.

(4) Locked Rotor

The locked rotor event was reanalyzed because of the potential effect of the positive MTC on the nuclear power transient and thus on the RCS pressure and fuel temperature. A positive MTC will not affect the time to DNB because DNB is conservatively assumed to occur at the beginning of the transient. The results show that a zero MTC at 100% power is more limiting than the allowable positive MTC at 70% power. The results show peak RCS pressure and peak pellet averaged and peak cladding temperatures less than in the previously approved FSAR analyses, which is acceptable.

(5) Loss of External Electric Load

The loss of external electric load transient was reanalyzed for beginning of cycle (BOC) since the MTC will be negative at end of cycle (EOC) and will give the same results as in the FSAR. Two cases were analyzed: (a) reactor in the automatic rod control mode with operation of the pressurizer spray and pressurizer power-operated relief valves (PORVs) and (b) reactor in the manual control mode with no credit for pressurizer spray or PORVs. The result of a loss of load is a core power that momentarily exceeds the secondary system power removal, causing an increase in RCS coolant temperature. The reactivity addition from a positive MTC, causes an increase in both nuclear power and RCS pressure. The result for the control rods in the automatic control and assuming pressurizer spray and relief is an RCS pressure of 2436 psia following a reactor trip on overtemperature $\Delta T$. A minimum DNBR well above the limit of 1.3 is reached shortly after reactor trip. The result for the case of rods in manual control with no credit for pressure control is a peak RCS pressure of 2557 psia following a reactor trip on high pressure. The minimum DNBR increases throughout the transient. Because the DNBR remains above 1.3 and the peak RCS pressure is less than 110% of design, the conclusions presented in the previously approved FSAR analysis are still applicable.

(6) Control Rod Ejection

The rod ejection transient was reanalyzed only for BOC since the MTC will be negative at EOC and the existing FSAR analysis remains applicable for

EOC. The higher nuclear power levels and hotspot fuel temperatures resulting from a rod ejection are increased by a positive MTC. The results from the BOC reanalysis show that the fuel and cladding temperatures are within the limiting values specified in the existing FSAR analysis. The peak hotspot fuel centerline temperature exceeded the melting temperature for the full-power case; however, melting was restricted to less than the innermost 10% of the pellet. The fuel and cladding temperatures do not exceed the limits specified in the previously approved FSAR analysis. Therefore, the results of the control rod ejection reanalysis are acceptable.

Conclusion

Since the reanalysis of the affected plant transients does not result in exceeding any of the fuel limits or safety limits specified in the previously approved FSAR analysis, the staff concludes the FSAR revisions supporting operation with a positive moderator temperature coefficient of +5 pcm/°F up to 70% power, and decreasing linearly from this to 0 pcm/°F at full power will not pose an undue risk to the health and safety of the public, and are, therefore, acceptable.

## 4.4 Thermal-Hydraulic Design

### 4.4.3 Design Anormalities

#### 4.4.3.1 Crud Deposition

It was stated in the SER that the applicant had proposed an RCS flow measurement uncertainty value less than the Westinghouse Standard Technical Specification value of 3.5%. This required submittal of an analysis for staff review. In a letter from S. R. Zimmerman, CP&L, to H. R. Denton, NRC, dated July 25, 1986, the applicant submitted an RCS flow measurement analysis. This was to support an RCS flow uncertainty of 2.0% in Technical Specification 3/4.2.3. Because of an additional 0.1% penalty for undetected fouling of the feedwater flow venturi meter, the nominal RCS flow measurement uncertainty is raised to 2.1%. The staff has completed its review of the flow measurement analysis and finds that the RCS flow measurement uncertainty of 2.1% is acceptable.

### 4.4.6 NUREG-0737 Item II.F.2, Instrumentation for Inadequate Core Cooling Detection

In SER Supplement 1, the staff stated that the license would be conditioned, in the area of inadequate core cooling instrumentation (ICCI), as follows.

(1) ICCI will be installed and preoperational tests will be completed before fuel load. Startup tests and calibrations for which the core must be in place will be completed before operation above 5% of full power.

(2) Before the plant exceeds 5% power, an implementation letter report must be provided for staff review.

(3) Before criticality, the modified emergency procedures that incorporate the generic Westinghouse RVLIS system for Shearon Harris must conform to generic EOP guidelines relating to the use of the RVLIS, or deviations must be identified and explained.

By letters dated May 29 and August 29, 1986, the applicant committed to the requirements of items 1 and 2 above and thus removes the need to make it a condition of the license. In regard to item 3 above, the applicant, by letters dated September 18, 1984, and April 28, 1986, provided information on plant-specific emergency response guidelines and referenced the Westinghouse Emergency Response Guidelines (EPGs). The staff concludes that because the Shearon Harris plant-specific technical guidelines retain the basic mitigating strategies of the Westinghouse ERGs, they contain adequate technical basis. Therefore, Shearon Harris' modified emergency procedures conform to the generic emergency operating procedures guidelines, thus satisfying the license condition (item 3 above). Thus, SER License Condition 8 on items 1, 2, and 3 above is no longer required and has been deleted.

# 5 REACTOR COOLANT SYSTEM

## 5.2 Integrity of Reactor Coolant Pressure Boundary

### 5.2.2 Overpressure Protection

#### 5.2.2.2 Overpressure Protection During Low-Temperature Operation

It was stated in the SER that "the low-temperature overpressure protection is primarily provided by the pressurizer PORVs (two of the three PORVs are used) with automatically adjusted opening setpoints (to be specified later) that vary as a function of reactor coolant temperatures." By letter dated April 23, 1986, from S. R. Zimmerman, CP&L, to H. R. Denton, NRC, the applicant supplied information on the setpoints (Confirmatory Issue 10). The applicant stated that the overpressure PORV setpoints were so determined that the reactor vessel's Appendix G (10 CFR 50) curve will not be exceeded. The applicant's evaluation considered the inadvertent actuation of single safety injection pump or a heat input for a coolant pump start, assuming a 50 Fahrenheit degrees temperature mismatch of the steam generator primary and secondary sides. The arming temperature for each PORV is 335°F and a pressure alarm will be received 25 psi below the PORV setpoint. The setpoints provided are shown below.

| RCS temperature (°F) | Low PORV setpoint (psig) | High PORV setpoint (psig) |
|---|---|---|
| 100 | 390 | 400 |
| 125 | 400 | 410 |
| 250 | 400 | 410 |
| 300 | 425 | 435 |
| 335 | 440 | 450 |
| 350 | 2400 | 2400 |

The above setpoints for the reactor coolant system (RCS) temperature range from 100°F to 335°F and are implemented in the Technical Specifications for Shearon Harris Unit 1 in Technical Specification Figure 3.4-4. The PORV pressure setpoint value at 350°F is for operation in modes 1 to 3 and also for mode 4 when the temperature of all the RCS cold legs is greater than 335°F. The staff finds this confirmatory information acceptable and considers Confirmatory Issue 10 resolved.

### 5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

This section was prepared with the technical assistance of Department of Energy (DOE) contractors from the Idaho National Engineering Laboratory.

#### 5.2.4.3 Evaluation of Compliance With 10 CFR 50.55a(g)

This evaluation supplements conclusions in this section of the SER which addresses the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). SER Supplement 2 reported that the staff considered the review of the preservice inspection (PSI) program for the reactor coolant pressure boundary to be a confirmatory issue (SER Confirmatory Issue 34) based on the staff's review of the Shearon Harris Nuclear Power Plant Unit 1 PSI Program, which was determined to be acceptable, and contingent on the applicant submitting all relief requests with supporting technical justifications.

Since Supplement 2 was issued, the staff has reviewed (1) the FSAR through Amendment 31 dated July 1986, (2) Revision 2 of the Shearon Harris PSI Program Plan submitted September 23, 1985, (3) a letter from the applicant dated November 5, 1985, regarding the preservice inspection of component supports, (4) a January 7, 1986, submittal containing a listing of requests for relief from the ASME Code Section XI requirements that the applicant has determined not practical for Shearon Harris Unit 1, (5) a March 13, 1986, submittal notifying the staff of the applicant's intent to upgrade the PSI Program Plan to comply with ASME Code Section XI, 1980 Edition with Addenda through Winter 1982, and (6) revised and updated relief request submittals dated June 2 and August 6, 1986.

The applicant stated that the January 7, 1986, submittal of relief request information updates and supersedes the information submitted September 23, 1985, and contains a complete listing of known specific relief requests to date. As a result of discussions with the applicant and the staff's request for additional information dated April 22, 1986, this document was revised and resubmitted on June 2, 1986, and was further revised August 6, 1986. The revisions deleted some of the relief requests and contained clarification along with new and revised requests for relief which were supported by information pursuant to 10 CFR 50.55a(a)(3). The staff evaluated the ASME Code-required examinations that the applicant determined to be impractical and found that the applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

On the basis of the granting of relief from these preservice examination requirements and review of the applicant's submittals, the staff concludes that the preservice inspection program for the reactor coolant pressure boundary at Shearon Harris Nuclear Power Plant Unit 1 is acceptable and in compliance with 10 CFR 50.55a(g)(3). The detailed evaluation supporting this conclusion is provided in Appendix J to this supplement.

The initial inservice inspection program has not been submitted. This program will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b), but before the first refueling outage when inservice inspection commences.

## 5.3 Reactor Vessel

### 5.3.4 Pressurized Thermal Shock

The applicant included a conservative estimate in the FSAR in 1983 based on the (then) proposed pressurized thermal shock rule (FSAR Section 5.3.1). On the basis of that estimate, the staff concluded that the facility could be operated without undue risk to the health and safety of the public. Amendment 27 of the FSAR responds to the pressurized thermal shock rule as published in 10 CFR 50.61.

In Appendix C of the SER, the staff reviewed the reactor vessel beltline materials in accordance with the criteria in Commission Report SECY-82-465 (November 23, 1982), "Pressurized Thermal Shock." The present staff acceptance criteria for protection against pressurized thermal shock (PTS) events are documented in 10 CFR 50.61, which was published in the Federal Register on July 23, 1985.

The controlling beltline material from the standpoint of PTS susceptibility was identified to be plate B4197-2. The material properties of the controlling material and the associated chemistry reactors reported by the utility and confirmed in the staff's evaluation are:

| Material properties | Utility submitted | Staff evaluation |
|---|---|---|
| Cu, Copper content (%) | 0.10 | 0.10 |
| Ni, Nickel content (%) | 0.50 | 0.50 |
| I, Initial $RT_{NDT}$ (°F) | 90 | 90 |
| M, Margin (°F) | - | 48 |
| CF, Chemistry factor (°F) | - | 54.5 |

The source of the values reported by the utility and their relationship to the actual beltline materials are identified in a letter from the applicant dated July 31, 1986. On the basis of the information in this letter, the controlling material has been properly identified. The margin has been derived from consideration of the bases for these values, following the requirements in 10 CFR 50.61. Assuming that the reported values of fluence are correct, Equation 1 of the PTS rule governs, and the chemistry factor is as shown above.

The staff concludes that the material properties and the chemical composition of the controlling beltline material are acceptable.

The following evaluation concerns the estimation of the fast neutron fluence ($E \geq 1.0$ MeV) to the inside surface of the pressure vessel and the corresponding value of the $RT_{PTS}$ for 32 effective full-power years of operation. The analysis of the neutron transport was performed with the discrete ordinates code DOT. The cross-sections were derived from the SAILOR code which is ENDF/B-IV based. The $P_3$ scattering approximation was used. For the neutron sources, power distributions representative of time-averaged conditions derived from statistical studies of long-term operation of Westinghouse three-loop plants were employed. These power distributions included rodwise spatial variations for the peripheral assemblies. It should be noted that the source distribution was based on the out-in fuel management; the applicant, however, committed to future low leakage loading patterns. The methodology, the cross-sections, and the sources assumed are conservative and acceptable.

The applicable equation specified in 10 CFR 50.61 for the Shearon Harris vessel is

$$RT_{PTS} = I + M + (-10 + 470 \times Cu + 350 \times Cu \times Ni) \times f^{0.27}$$

where:

$I$ = initial $RT_{NDT}$ = 90°F

$M$ = uncertainty margin = 48°F

Cu = w/o copper in plate B4197-2 = 0.10
Ni = w/o nickel in plate B4197-2 = 0.50
f = peak fluence on plate B4197-2 for 32 effective full-power years of operation, E > 1.0 MeV in units of $10^{19}$ n/cm$^2$ = 7.3

Then:

$$RT_{PTS} = 90 + 48 + (-10 + 470 \times 0.1 + 350 \times 0.1 \times 0.50) \times 7.3^{0.27}$$
$$= 138 + 54.5 \times 1.71 = 231.2°F$$

which is smaller than 270°F (the applicable 10 CFR 50.61 criterion) and, thus, acceptable.

In view of

- the pressure-temperature updating requirements for the fracture toughness of the beltline material in 10 CFR 50 Appendix G
- the fact that the $RT_{PTS}$ value is readily available from the calculation of the pressure/temperature limits
- the staff desire to be informed on the current value of the $RT_{PTS}$ for all pressurized water reactors (PWRs)

the staff requests that the applicant submit a reevaluation of the $RT_{PTS}$ and a comparison to the prediction of FSAR Section 5.3.7 along with the future pressure-temperature operating limits which are required by 10 CFR 50 Appendix G.* It should be noted that this reevaluation is a requirement in 10 CFR 50.61, whenever core loadings, surveillance measurements, or other information indicate a significant change in projected values.

## 5.4 Component and Subsystem Design

### 5.4.2 Steam Generators

#### 5.4.2.2 Steam Generator Tube Inservice Inspection

In Section 5.4.2 of the SER, the staff identified a generic problem concerning potential tube degradation caused by flow-induced vibration in preheater sections of Westinghouse Model D steam generators. In October 1983, the staff issued NUREG-1014, "Safety Evaluation Report Related to the D4/D5/E Steam Generator Design Modification," which accepted the modifications proposed by the Counter Flow Steam Generator Owners Group (CFSGOG). These included expansion of certain steam generator tubes and directing some of the main feedwater flow through the auxiliary feedwater nozzle at full-power conditions. The applicant is a member of CFSGOG and is committed to updating the FSAR to include the revisions in the transient and accident analysis margins resulting from the D4 modifications. These revisions were submitted in FSAR Amendments 17 and 19. The applicant has also implemented the CFSGOG recommendation

*This request for information is covered under OMB Clearance No. 3150-0011.

regarding feedwater flow, specifically by routing 18% of the main feedwater supply via the auxiliary feedwater nozzle at full load conditions.

The staff has reviewed the transient and accident analyses revisions that were necessitated by the steam generator tube vibration problem. These included FSAR Sections 15.1.2, "Feedwater (FW) System Malfunction That Result in Increase in FW Flow"; and 15.1.3, "Excessive Increase in Secondary Steam Flow"; and 15.2.8, "FW System Pipe Break." The applicant did not revise FSAR Section 15.2.7, "Loss of Normal FW Flow," but the consequences of this transient would be bounded by the feedwater pipe break. The staff concludes that the effects of the design changes necessitated by the tube vibration problem are minor and do not affect the conclusions in the Shearon Harris SER.

In Section 5.4.2.2 of the Shearon Harris SER, the staff also stated that it would require the applicant to use NUREG-0452, Revision 2, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors," in the preparation of its steam generator tube inservice inspection program. Subsequently, the staff required the applicant to use Draft Revision 5 to NUREG-0452 to prepare the above-cited inspection program. The staff has completed its review of Section 4.4.5 of the Technical Specifications on this matter and concludes that this issue is resolved.

## 5.4.7 Residual Heat Removal System (RHRS)

### 5.4.7.5 Tests, Operational Procedures, and Support Systems

Branch Technical Position (BTP) RSB 5-1 requires, in part, that the preoperational and initial startup test program

> Shall include tests with supporting analyses to (a) confirm that adequate mixing of borated water added prior to or during cooldown can be achieved under natural circulation conditions and permit estimation of the times required to achieve such mixing, and (b) confirm that the cooldown under natural circulation conditions can be achieved within the limits specified in the emergency operating procedures. Comparison with performance of previously tested plants of similar design may be substituted for these tests.

This requirement applies to Class 2 plants, such as Shearon Harris. The staff position is that these tests should simulate a loss of offsite power at a high power level and be continued to cold shutdown conditions.

The applicant's response to Staff Question 440.20 with regard to compliance of each item of BTP RSB 5-1 indicates that the plant design provides the capability for conducting natural circulation cooldown tests if required, but because of great similarity in design between all Westinghouse pressurized water reactors, Shearon Harris will reference those tests conducted at other units rather than conducting such tests at the Shearon Harris plant.

The only Westinghouse plant natural circulation tests performed to date that appear to meet the requirements of BTP RSB 5-1 are the Diablo Canyon tests. However, Diablo Canyon is a four-loop plant and there may be other significant differences between the two plants, such as upper vessel head temperatures.

In view of this, the staff requires that the applicant meet its commitment regarding referencing tests conducted at other plants by demonstrating that the Diablo Canyon tests are applicable to Shearon Harris. This should include demonstration of hydraulic similarities in the core, upper vessel head, and loops. As an alternate, the applicant can commit to perform a natural circulation and boron mixing test from high power to cold shutdown at Shearon Harris. This issue must be satisfactorily resolved before startup after the first refueling. The staff further concludes that there is reasonable assurance the Shearon Harris plant can operate for one cycle until this issue is resolved since (1) natural circulation has been demonstrated on other Westinghouse plants, (2) a natural circulation test will be conducted from low power during the startup test program to meet the requirements of Item I.G.1 of NUREG-0694, (3) systems required for natural circulation cooldown (e.g., auxiliary feedwater and RHR system) are safety grade, and (4) there is an ample auxiliary feedwater supply from seismic Category I sources.

# 6 ENGINEERED SAFETY FEATURES

## 6.2 Containment Systems

### 6.2.4 Containment Isolation System

Confirmatory Item 13 of the SER identified a need to revise the FSAR containment penetration table. FSAR Table 6.2.4-1 was revised in Amendment 29. The staff reviewed the changes in the table and provided comments to the applicant on the applicable general design criteria and acceptable deviations from explicit requirements for several penetrations, and on type C testing requirements for these valves. By letter dated September 25, 1986, the applicant revised FSAR Table 6.2.4-1 to reflect the staff's comments. The staff has reviewed this table and finds it acceptable. Therefore, Confirmatory Item 13 is resolved.

In FSAR Amendment 29, the applicant described the reactor vessel level instrumentation system (RVLIS) sensing lines. The six sensing lines penetrate the containment and are required to remain functional following a loss-of-coolant accident (LOCA) or steamline break. These lines sense reactor vessel level and reactor coolant system pressure, and are connected to pressure and level transmitters outside containment. The RVLIS instrumentation provides an indication of reactor vessel level and, hence, the approach to inadequate core cooling. Therefore, it is essential that these lines remain open following an accident. Double-barrier isolation is provided by means of a sealed bellows inside containment and a diaphragm in the hydraulic isolator outside containment. If the instrument line breaks outside containment, the sealed bellows prevents leakage of containment atmosphere. If the instrument line breaks inside containment, the diaphragm in the hydraulic isolator prevents leakage. The staff concludes that the combination of the sealed bellows and the diaphragm in the hydraulic isolation provides an acceptable alternative to the explicit requirements of General Design Criterion (GDC) 55 (Appendix A to 10 CFR 50) for containment isolation provisions, on the basis of the double-barrier design and the RVLIS safety function.

### 6.2.6 Containment Leakage Testing Program

Type C Testing Program

In Section 6.2.4 of the SER, the staff identified a confirmatory issue that would require the applicant to amend its FSAR Table 6.2.4-1 for containment isolation valves (CIVs). This confirmatory issue was a result of the applicant's misinterpretations of GDCs 55, 56, and 57. Certain containment penetrations and CIVs had been incorrectly classified by the applicant. To close this issue, the applicant was required to revise the FSAR Table 6.2.4-1 in accordance with staff interpretation of GDC 55, 56, and 57, and SRP Section 6.2.4.

The staff also concluded its review of the containment leakage rate testing program in Section 6.2.6 of the SER. The staff's review covered all containment penetrations and associated CIVs that are contained in FSAR Table 6.2.4-1. It has been and still is the staff's position that without acceptable justification, all CIVs must be type C tested.

In Amendment 29 to the Shearon Harris FSAR, dated July 25, 1986, the applicant revised the FSAR Table 6.2.4-1. In the revised table, the applicant correctly classified the containment penetrations in accordance with GDC 55, 56 and 57. However, certain CIVs were still classified as non-CIVs by taking exception to GDC 55. The applicant was informed by the staff that an exception to GDC 55 was not acceptable for those valves identified in FSAR Table 6.2.4-1. The applicant did not conform to the GDC requirements until September 17, 1986, when the staff denied the applicant's request for taking exception to GDC 55 for certain CIVs.

The intent of taking exception to GDC 55 was to avoid leak testing certain CIVs; i.e., not declaring a valve to be a CIV automatically exempts it from type C testing under Appendix J to CFR 50. During a discussion of September 17, 1986, the applicant agreed to classify the valves in question as CIVs. By letter dated September 25, 1986, the applicant formally proposed to revise its type C testing program. The following is a discussion and evaluation of the penetrations and valves that were not being tested under the proposed revisions to the program.

Penetrations M-17, 20, 21, and 22

Containment Penetrations M-17, M-20, M-21, and M-22 serve the high head safety injection system. The applicant proposes not to type C test the containment isolation valves associated with these penetrations because they would be provided with a pressurized water seal at a pressure greater than 1.10 times the accident pressure ($P_a$) for a minimum of 30 days following a design-basis LOCA. The applicant states that the water seal is provided by the ECCS low head safety injection (LHSI) pumps via the suction crossover or the ECCS high head safety injection (HHSI) pumps and the system piping from the suction crossover to these penetrations. Furthermore, the applicant states that no single active failure can prevent effective water sealing of these penetrations. The outside containment isolation valves related to these penetrations are gate type with a single piece wedge. According to the applicant, the valve design allows for stem/packing leakage only from the high pressure side of the wedge. Given that a water seal at a pressure greater than 1.1 $P_a$ will be maintained on the outer side of the valve, no containment atmosphere can enter the stems or packing and be released to the outside environment.

On the basis of the above description of the system operation and valve design, the staff concurs with the applicant that these penetrations and associated containment isolation valves, if closed to perform their containment isolation function, will be sealed with water via either LHSI or HHSI pumps with a continuous supply of sealing water from the containment sumps. In accordance with paragraph III.C.3 of Appendix J to 10 CFR 50, because the containment isolation valves of these penetrations will be maintained under a water seal for at least 30 days following the an accident, they are not potential containment atmosphere leak paths, and therefore, do not require a type C test with air or nitrogen. In addition, a water leakage rate test is not needed, since a continuous supply of sealing water is provided from the containment sumps.

Penetration M-18

Containment penetration M-18 serves the low head safety injection systems. The applicant proposes not to perform type C testing for the containment isolation valves associated with this penetration because they are provided with a pressurized water seal at a pressure greater than 1.10 times the accident pressure ($P_a$) for a minimum of 30 days following a design-basis LOCA. The applicant states that the water seal is provided by the ECCS low head safety injection (LHSI) pumps via the crossover line located outside containment. Furthermore, the applicant states that no single active failure can prevent effective water seal of this penetration. The outside containment isolation valve of this penetration is a gate type with a single piece wedge. According to the applicant, the valve design allows for stem/packing leakage only from the high pressure side of the wedge. Given that a water seal at a pressure greater than 1.10 $P_a$ will be maintained on the outer side of the valves, no containment atmosphere can enter the stems or packing and be released to the outside environment.

On the basis of the above description of the system operation and valve design, the staff concurs with the applicant that this penetration and associated isolation valves, if closed to perform their containment isolation function, will be sealed with water via LHSI pumps with a continuous supply of sealing water from the containment sumps. In accordance with paragraph III.C.3 of Appendix J to 10 CFR 50, because the containment isolation valves of this penetration will be maintained with a water seal for at least 30 days, they are not potential containment atmosphere leak paths, and therefore, do not require a type C test with air or nitrogen. In addition, a water leakage rate is not needed, since a continuous supply of sealing water is provided from the containment sump.

Penetrations M-37 and M-38

Containment penetrations M-37 and M-38 serve the reactor coolant drain tank and the excess letdown heat exchangers. The applicant proposes not to perform type C testing on the containment isolation valves including the two relief valves, because the components inside containment form a closed system. The staff finds acceptable the proposal for not performing type C testing on these penetrations.

Conclusion

In conclusion, the staff finds, on the basis of the above evaluation, that the applicant's proposed revisions to the type C testing program, as described in its letter dated September 25, 1986, complies with the requirements of Appendix J to 10 CFR 50 and is, therefore, acceptable.

## 6.3 Emergency Core Cooling System

### 6.3.5 Performance Evaluation

#### 6.3.5.1 Large-Break LOCA

The applicant submitted the results for a revised large-break LOCA (LBLOCA) analysis in a letter from S. R. Zimmerman, CP&L, to H. R. Denton, NRC, dated August 26, 1986. The LBLOCA was reanalyzed using the 1981 ECCS Evaluation Model with BART with the corrections and additions set forth in Westinghouse report WCAP-9561, Addendum 3, Revision 1, dated July 24, 1986. The resulting allowable peaking factor, $F_q$, is 2.28 and the peak cladding temperature (PCT) is 2113°F. The corresponding previous values in the SER, which used the 1978 ECCS (emergency core cooling system) Evaluation Model were $F_q$ of 2.11 and PCT of 2181°F.

The LBLOCA analysis was performed for a power level of 2775 MWt with the $F\Delta H$ of 1.55. The analysis utilized initial fuel conditions generated by the Revised Pad Thermal Safety Model (Westinghouse WCAP-8720, Addendum 3, Revision 1). The analysis assumed a 6% steam generator tube plugging level, 17 x 17 standard fuel, and an accumulator water volume of 1050 $ft^3$ per tank. As in the previous analysis, the limiting break size is a double-ended cold-leg guillotine (DECLG) break with a Moody discharge coefficient of 0.4. The analysis results indicated that the PCT is 2113°F, the maximum local metal-water reaction is 4.6%, and the total core metal-water reaction is less than 0.3% for all breaks. This compares, respectively, to the 2200°F PCT, 17% maximum cladding oxidation, and 1% maximum hydrogen generation limits specified in 10 CFR 50.46. As the applicant's results are well below the limits specified in 10 CFR 50.46, they are acceptable. In addition, the results showed that the cladding temperature transient is terminated at a time when the core geometry is still amenable to cooling. As a result, the core temperature will continue to drop and the ability to remove decay heat generated in the fuel for an extended time period will be provided. This, therefore, acceptably fulfills the requirements of 10 CFR 50.46 for coolable geometry and capability for long-term cooling.

#### 6.3.5.2 Small-Break LOCA

The applicant has submitted a plant-specific analysis (letter from A. B. Cutter, CP&L, to H. R. Denton, NRC, dated June 20, 1986) for a spectrum of small-break LOCA analyses (2-inch; 3-inch, 4-inch). These identify that the 3-inch break is the limiting small break; the calculated peak PCT is 1751°F, the local metal-water reaction is 2.23%, and the corewide oxidation is less than 0.3%. The analyses were performed using the NOTRUMP code which is an approved code satisfying the requirements of TMI Action Plan Item II.K.3.30.

The applicant's results are well below all acceptance criteria limits of 10 CFR 50.46. The staff has reviewed the applicant's evaluation and concludes that it is acceptable and that the applicant has met the requirements of TMI Action Plan Item II.K.3.31.

## 6.4 Control Room Habitability

This evaluation pertains to control room habitability during a chlorine release accident. In its letter dated June 24, 1986, and amended by letter dated

August 25, 1986, the applicant indicated that the Shearon Harris control room does not meet certain positions of Regulatory Guide (RG) 1.95, Revision 1, "Protection of Nuclear Power Plant Operators Against an Accidental Chlorine Release." Specifically, instead of the 10-second closure time suggested by the regulatory guide, the control room outside air intake dampers will close within 38.2 seconds (23.2 seconds for detection and processing time and 15 seconds for isolation valve closure); also, the pressurization test flow rate for demonstrating control room integrity exceeds the regulatory guide suggested limit of 0.06 volume change per hour. Accordingly, the applicant submitted an analysis following the methodology of NUREG-0570, "Toxic Vapor Concentration in a Control Room Following a Postulated Accidental Release," to justify the plant design against accidental chlorine releases.

The two cases analyzed were (1) accidental chlorine releases from outside the plant boundary at the nearest rail and road transportation corridor and (2) rupture of one onsite storage chlorine tank.

Per RG 1.78, the staff considers control room personnel are adequately protected from chlorine releases if operators can don protective air-breathing face masks within 2 minutes from receiving an alarm, before the chlorine concentration in the room reaches 15 ppm (45 mg/m$^3$). The concentration at the outside air intake and walls is to be predicted by using the highest statistical $\chi/Q$ that is exceeded only 5% of the time for winds occurring in the exposure pathway direction.

The applicant's analysis departs from RG 1.78 by using 25 ppm as the upper exposure limit instead of 15 ppm. The higher level was selected on the basis of a joint study prepared by the National Institute for Occupational Safety and Health (NIOSH) and the Occupational Safety and Health Administration (OSHA) titled, "Pocket Guide to Chemical Hazards," dated September 1978. This 25-ppm limit is defined by this study group as the maximum level from which one could escape within 30 minutes without any impairing symptoms or any irreversible health effects.

For the meteorological conditions applicable (i.e., worst case $\chi/Q$ conditions exceeded only by 5% of winds in the study case directions) and using an isolated control room outside air inleakage estimate of 315 cfm, the operators were alerted by the remote (at the chlorine storage area) and local (at the air intake duct) detectors with sufficient time to don masks before the control room concentration exceeded 25 ppm. Even though the applicant identified a potential higher acceptable limit, the staff notes that in no case did the concentration exceed 15 ppm (RG 1.78 criteria) before operator protection can be taken for both onsite and offsite chlorine releases for the said meteorological conditions.

Part of the pathway methodology for estimating the control room concentration is to consider inleakage for the isolated control room. The applicant estimated the inleakage to be 315 cfm. The staff agrees with the applicant's analysis that inleakage should be less than 315 cfm. The applicant demonstrated that with inleakage at 315 cfm, the operators still have sufficient time to don masks to protect themselves. Therefore, the staff will require that the Technical Specifications reflect periodic testing of the control room to verify that the control room pressure can be maintained greater than or equal to 1/8-inch water gauge and the pressurization flow will not exceed 315 cfm. Technical Specification Issue 17 is closed.

## 6.6 Inservice Inspection of Class 2 and 3 Components

This section was prepared with the technical assistance of Department of Energy contractors from the Idaho National Engineering Laboratory.

### 6.6.3 Evaluation of Compliance With 10 CFR 50.55a(g)

This evaluation supplements conclusions in this section of the SER which addresses the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). SER Supplement 2 previously reported that the staff considered the review of the preservice inspection (PSI) program for Class 2 and 3 components to be a confirmatory issue based on the staff review of the Shearon Harris Nuclear Power Plant Unit 1 PSI Program, which was determined to be acceptable, and contingent upon the applicant revising the system (to correct an omission reported in the May 9, 1985, letter) and submitting all relief requests with supporting technical justifications.

Since Supplement 2 was issued, the staff has reviewed (1) the FSAR through Amendment 31 dated July 1986; (2) Revision 2 of the Shearon Harris PSI Program Plan submitted September 23, 1985; (3) a letter from the applicant, dated November 5, 1985, regarding the preservice inspection of component supports; (4) a January 7, 1986, submittal containing a listing of requests for relief from the ASME Code Section XI requirements that the applicant has determined not practical for Shearon Harris Unit 1; (5) a March 13, 1986, submittal notifying the staff of the applicant's intent to upgrade the PSI Program Plan to comply with ASME Code Section XI, 1980 Edition with Addenda through Winter 1982; and (6) revised and updated relief request submittals dated June 2 and August 6, 1986.

The September 23, 1985, submittal of the Shearon Harris PSI Program Plan, Revision 2, contained the applicant's commitment to perform a volumetric examination of line numbers 2CT8-10 and 2CT8-15 in the containment spray system. With this addition, the staff considers the selection of Code Class 2 and 3 components for PSI examination at Shearon Harris Unit 1 acceptable.

The applicant stated that the January 7, 1986, submittal of relief request information updates and supersedes the information submitted September 23, 1985, and contains a complete listing of known specific relief requests to date. As a result of discussions with the applicant and the staff's request for additional information dated April 22, 1986, this document was revised and resubmitted on June 2 and August 6, 1986. The revisions deleted some of the relief requests and contained clarification along with new and revised requests for relief which were supported by information pursuant to 10 CFR 50.55a(a)(3). The staff evaluated the ASME Code-required examinations that the applicant determined to be impractical and determined that the applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

On the basis that relief from these preservice examination requirements is granted and review of the applicant's submittals, the staff concludes that the preservice inspection program for Code Class 2 and 3 components at Shearon

Harris Nuclear Power Plant Unit 1 is acceptable and in compliance with 10 CFR 50.55a(g)(3). The detailed revaluation supporting this conclusion is provided in Appendix J to this supplement.

The initial inservice inspection program has not been submitted. This program will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b), but before the first refueling outage when inservice inspection commences.

# 7 INSTRUMENTATION AND CONTROLS

## 7.3 Engineered Safety Features Systems

### 7.3.3 Evaluation Findings

#### 7.3.3.9 Spare Component Cooling Water (CCW) Pump

A spare CCW pump is provided to allow continued plant operation when one of the two CCW pumps is out of service. In Section 7.3.3.9 of the SER, the staff requested that the applicant revise the proposed Technical Specifications to include special surveillance testing of the spare pump breaker and the CCW surge tank level instruments. During the staff's review of the Technical Specifications, it was determined that a special surveillance test was not required because the Technical Specifications stipulate that the breaker will be tested before the spare pump is declared operable. The special surveillance test of the CCW surge tank has been incorporated into Technical Specification 3/4.7.3.

The staff concludes that the above items have been adequately incorporated into the Technical Specifications and considers this matter resolved.

#### 7.3.3.10 Spare Charging Pump

A spare charging pump is provided to allow continued plant operation when one of the two charging pumps is out of service. In Section 7.3.3.10 of the SER, the staff requested that the applicant revise the proposed Technical Specifications to include a special surveillance test of the spare pump breaker. During the staff's review of the Technical Specifications it was determined that a special surveillance test was not required because the Technical Specifications stipulate that the breaker will be tested before the spare pump is declared operable.

The staff concludes that this matter has been adequately addressed in Technical Specification 3/4.1.2 and is considered resolved.

## 7.4 Systems Required for Safe Shutdown

### 7.4.1 Description

#### 7.4.1.3 Auxiliary Feedwater Control

The staff's review of the auxiliary feedwater system (AFWS) includes the following considerations:

(1) automatic initiation (discussed in SER Section 7.3)

(2) capability of controlling flows to establish and maintain steam generator level

(3) capability of controlling the steam generator pressure

(4) capability of isolating a faulted steam generator resulting from feedwater line or steamline breaks

(5) capability for post-trip control from auxiliary shutdown panel

The operator controls steam generator level by positioning the auxiliary feedwater (AFW) regulating valves. The two motor-driven pumps and their associated controls are redundant and powered from safety train A and B, respectively. The AFW pump turbine is driven by steam supplied from the main steam piping of two steam generators. The pump speed is automatically controlled by the differential pressure between pump discharge pressure and the turbine steam inlet pressure. The operator can control speed at the main control board or at the auxiliary control panel.

During cold shutdown, the main steam power-operated relief valves (PORVs) are automatically controlled by steamline pressure and the operator adjusts the pressure setpoint remotely (from the control room or the auxiliary shutdown panel). The operator adjusts the AFW flow rate and steam generator pressure setpoint to control the cooldown rate.

A system is provided to terminate AFW flow to a faulted steam generator. The differential pressures between all steam generators are compared and used in conjunction with the main steam isolation signal (MSIS) to determine a steamline break and terminate AFW flow to the faulty steam generator. The steam generator pressure mismatch signal and the MSIS are combined in a coincidence logic to develop a steam generator available signal (SGAS). An SGAS will close the AFW regulating and isolation valves to the faulty steam generator.

When the plant is in a shutdown condition, manual initiation of the selected auxiliary feedwater pumps is required. This can be accomplished by using the manual control switches provided on the main control board of the auxiliary shutdown panel. Auxiliary feedwater flow indication, pump suction and discharge pressures, AFW turbine speed, valve positions, steam generator level control, and level indications are provided on the main control board and the auxiliary shutdown panel. The staff finds the design of the auxiliary feedwater control acceptable.

### 7.4.2 Specific Findings

#### 7.4.2.2 Testing for Remote Shutdown Operation

In the SER, the staff was concerned that the remote shutdown capability test to verify design adequacy had not been performed. The applicant stated that emergency procedures would be prepared to include remote shutdown and a test would be conducted during startup testing to confirm the capability for remote shutdown. The test is described in FSAR Section 14.2.12.2.20.

On December 22, 1985, the applicant performed an integrated hot functional test to demonstrate operability of the remote shutdown capabilities from the auxiliary control panel. The resident inspectors and Region II inspector witnessed this test. The detailed test results were documented in two inspection reports, 50-400/86-08 and 10. The test has demonstrated cold shutdown capability of the plant from the auxiliary control panel. The staff has concluded that based on the applicant's commitment for remote shutdown operation testing as described in FSAR Chapter 14 and the integrated hot functional test performed, there is a reasonable assurance that the plant has remote shutdown capability from the auxiliary control panel. The staff considers this item resolved.

# 8 ELECTRICAL POWER SYSTEMS

## 8.1 General

In the SER, the staff stated that it would conduct a review of electrical drawings and would visit the site to view the installation and arrangement of electrical equipment and cables for the purpose of verifying proper implementation of the design as described in the FSAR. A site visit was conducted on January 28-30, 1986, during which certain concerns were identified. These concerns were discussed with the applicant and identified in the meeting summary of April 28, 1986. The staff's evaluation and the applicant's proposed modifications or justification are discussed below.

During the site visit, the staff noted the following deficiencies:

(1) The implementation of identification and color coding schemes for safety-related circuits and equipment was inadequate.

(2) The showers in the battery rooms are not enclosed and are close to the batteries, thereby creating the likelihood of shower spray causing potential damage to the batteries.

(3) The as-installed dc power system alarms in the control room are inadequate in that there is only one battery trouble alarm provided for both redundant trains (125-V dc Emergency Bus A/B Trouble).

By letter dated June 18, 1986, the applicant provided responses to the above findings. The staff's evaluation of these responses follows:

For item 1 above, the applicant has instituted an equipment labeling program in accordance with the plant Program Procedure PLP-610, "Equipment Identification and Numbering System." This program will ensure that plant equipment will be properly identified. The Plant Equipment Deficiency Program identified in Administrative Procedure AP-038 will be used to identify missing equipment labels which had been previously installed. Considering this response, the staff finds this deficiency resolved.

For item 2, the applicant has stated that any inadvertent water spray from the showers/eye wash station in the battery rooms will have no adverse effect on the Class 1E dc system for the following reasons. The Class 1E dc system is an ungrounded system; therefore, a continuous path between positive and negative connections would be required to cause any electrical fault. The structure of the battery cell is such that the lugs and the attached bus bar are raised off the top of the cells. The cell tops do not have a lip, therefore, water pooling on the top of the batteries is not possible. On this basis, the staff concludes that the design provides assurance that the batteries will not be damaged or shorted by the inadvertent water spray and is acceptable.

For item 3, the applicant has committed to modify the current design to provide a second annunciator window in the main control room and in the auxiliary control room to differentiate between 125-V dc Emergency Bus A and Bus B trouble alarms. This satisfies the staff's concern and is acceptable.

## 8.3 Onsite Power Systems

### 8.3.1 AC Power Systems

#### Emergency Diesel Generator Reliability

The NRC staff has been evaluating the reliability of the standby emergency diesel generators (EDGs) manufactured by Transamerica Delaval, Inc. (TDI) which are used at Shearon Harris and at other sites. Concerns regarding the reliability of large-bore, medium-speed, diesel generators manufactured by TDI for application at domestic nuclear plants were first prompted by a crankshaft failure at the Shoreham Nuclear Power Station in August 1983. However, a broad pattern of deficiencies in critical engine components subsequently became evident at Shoreham and at other facilities employing TDI diesel generators. These deficiencies stemmed from inadequacies in design, manufacture, and QA/QC (quality assurance/quality control) by TDI.

Shearon Harris Unit 1 is served by two TDI Model DSRV-16-4 diesel engines, designated EDGs 1A and 1B. These EDGs are "V" configuration, 16-cylinder, 4-cycle, turbocharged, aftercooled engines. Each has a nameplate continuous load rating of 6500 kW, an overload rating of 7150 kW, and operates at 450 rpm with a brake mean effective pressure (BMEP) of 209 psig.

The applicant has been actively involved in the TDI Diesel Generator Owners Group, an organization formed by Carolina Power and Light Company and 12 other utilities to resolve reliability issues stemming from the early problems with TDI engines. With the assistance of the Owners Group, the applicant has largely completed a comprehensive program to verify and enhance the reliability of the Shearon Harris diesel generators for standby nuclear service. The staff's evaluation of this program as a basis for issuance of an operating license is provided herein.

(1) Background

On March 2, 1984, the TDI Diesel Generator Owners Group submitted a plan to the NRC staff which, through a combination of design review, quality revalidations, engine tests, and component inspections, is intended to provide an in-depth assessment of the adequacy of the respective utilities' TDI engines to perform their safety-related function.

The Owners Group program involves the following major elements:

- Phase I: Resolution of the 16 known generic problem areas intended by the Owners Group to serve as a basis for the licensing of plants during the period before the completion of Phase II of the Owners Group Program.

- Phase II: A design review/quality revalidation (DR/QR) of a large set of important engine components to ensure that their design and manufacture (including specifications and QA/QC) and operational surveillance and maintenance, are adequate.

- Expanded engine tests and inspections as needed to support Phases I and II.

The 16 known problem areas (Phase I issues) identified by the Owners Group include the engine base and bearing caps, cylinder block, cylinder liner, cylinder heads, cylinder head studs, crankshaft, connecting rods, connecting rod bearing shells, piston skirts, piston rods, rocker arm capscrews, turbochargers, jacket water pump, high-pressure fuel oil tubing, air start valve capscrews, and engine-mounted electrical cable.

The Owners Group has issued reports detailing its proposed technical resolution of each of the 16 Phase I issues. These generic reports analyze the operational history (including failure history) of each of these components. In addition, these reports evaluate the causes of earlier failures and problems as well as the adequacy of the components to meet functional requirements and provide recommendations concerning needed component upgrades, inspections, and testing.

The Owners Group has documented its findings with respect to Phase II in DR/QR reports issued for the individual plants. These DR/QR reports document the results of the design review and quality revalidation which was performed on all components critical to the operability and reliability of the engines, including the 16 components identified by the Owners Group as known problem areas. The Owners Group performed the design reviews and identified the component quality attributes to be verified. The actual component inspections to verify the quality attributes were generally performed by the individual utilities. Engineering dispositions made by individual utilities on the basis of the inspection results were reviewed by the Owners Group.

A DR/QR Report for Shearon Harris, Unit 1 (TDI Diesel Generator Owners Group, Revision 0, November 1984) was submitted to the staff by letter dated December 20, 1984. Revision 1 to the DR/QR Report, submitted by letter dated May 13, 1985, updated pertinent Phase I inspection results; Revision 2, submitted by letter dated June 5, 1986, revised Appendix II, the Owners Group Maintenance and Surveillance (OG M/S) Program. In letters dated July 28, September 11, and September 18, 1986, the applicant reported the status of the quality revalidation inspections for the Phase I components, justified the exceptions and deviations to the DR/QR recommendations, described how it is conforming to the staff generic SER for TDI diesel generators, and updated the maintenance and surveillance program.

(2) Evaluation

The Owners Group Program and the Owners Group findings and recommendations stemming from this program were reviewed by Pacific Northwest Laboratory (PNL) under contract to NRC. PNL retained the services of several expert diesel engine consultants as part of its review staff and documented its findings in a number of Technical Evaluation Reports (TERs). Subject to a few clarifications, as identified in NUREG-1216 (August 1986), "Safety Evaluation Report

Related to the Operability and Reliability of Emergency Diesel Generators Manufactured by Transamerica Delaval, Inc.," the staff concurs with the PNL conclusions and recommendations presented in the PNL TERs.

NUREG-1216 provides the staff's evaluation of the Owners Group findings and recommendations stemming from the program, and provides the regulatory requirements and recommendations necessary for the technical resolution of the generic TDI emergency diesel generator issue. The staff's evaluation endorses the Owners Group Program subject to the PNL recommendations and staff requirements and recommendations as specified in NUREG-1216. Therefore, NUREG-1216 is incorporated into the Shearon Harris SER by reference.

The applicant's letters of September 11 and 18, 1986, addressed those regulatory requirements and recommendations in NUREG-1216 that are applicable to the Shearon Harris DSRV-16 diesel generators. But for a few exceptions, as discussed in the following sections, and the discretionary recommendations which the applicant is not required to implement, the applicant is meeting the staff requirements and recommendations.

The staff has reviewed the status of the quality revalidation inspections as delineated in the applicant's letters of July 28, September 11, and September 18, 1986, for the Phase I components. Except for a few minor deviations from and exceptions to the Owners Group recommendations which the staff find acceptable, the applicant performed all the Owners Group recommendations for the Phase I components, and found that the components on the Shearon Harris diesel generators met or exceeded the Owners Group design criteria.

Subsection (a) which follows, focuses on the Phase I components for which an exception to the staff requirements and recommendations is being taken. Subsection (b) goes beyond the Phase I issues to address the overall status of the DR/QR Program (Phase II issues) at Shearon Harris. Subsection (c) addresses Appendix II, the engine maintenance and surveillance program, of the DR/QR which the staff considers to be a key aspect in ensuring the continued operability/reliability of the diesel generators for the life of the facility.

(a) Exceptions to Staff Requirements (Phase I Components)

Engine Base

Several TDI engine blocks, which were fabricated from Class 40 grey iron, exhibited a degenerate microstructure (Widmanstatten graphite) which substantially increases the potential for developing cracks. Since the engine base is fabricated from the same material, the staff, in NUREG-1216, recommended that the engine base should also be checked for this degenerate microstructure. Because this is a staff recommendation and not an Owners Group recommendation, the applicant completed its quality revalidation inspections of the engine base and reassembled the engines before the staff evaluation (NUREG-1216) was issued. The staff believes that any cracks in the engine base which develop as a result of a degenerate microstructure would not impair or degrade the engine reliability and operability over the short term. Therefore, the staff can allow the plant to operate until the first refueling outage before the applicant must verify the microstructure of the engine base. This will become a condition of the license.

## Cylinder Heads

NUREG-1216 recommends that diesel engines having cylinder heads with any through-wall weld repair of the fire deck should not be placed in nuclear standby service if the repair is performed from one side only (i.e., a "plug weld"). Since the coolant side of the fire deck is not readily accessible for weld repair, a repair from the combustion side only may leave defects on the coolant side that could compromise the integrity of the head. The applicant, in a phone conversation with the staff on September 24, 1986, clarified its September 11, 1986, letter response on this matter. Even though the Group III cylinder heads had been subjected to the upgraded vendor inspection program and the DR/QR inspections verification, the applicant stated that it could not verify that the cylinder heads did not have through-wall weld repairs of the fire deck. The applicant, therefore, committed to inspect all cylinder heads before licensing, and to replace any cylinder heads found with through-wall weld repairs as soon as possible, depending on Group III cylinder head availability. Because all cylinder heads are presently of Group III design and have been inspected in accordance with DR/QR, and because the operating license will be conditioned to include air roll tests to monitor head integrity, the staff finds the cylinder heads acceptable.

(b) Status of DR/QR Program (Phase II Components)

The staff's audit of the DR/QR Report up to Revision 1 showed that DR/QR inspections for the Phase II components were only partially complete. In discussions between the staff and the applicant on the Phase II portion of the program, the applicant stated that all the Phase II inspections are believed to be completed, but that the inspection reports would need to be checked to verify this fact. Because of the number of reports that need to be examined, and because failure to complete the DR/QR inspections of the Phase II components will not seriously impair the reliability and operability of the diesel generators, the staff does not require the completion of the Phase II component inspections before licensing. However, the staff does require that the applicant provide the status of Phase II inspections before full-power operation of Shearon Harris. Any inspections not completed by that time will be required to be completed before restart after the first refueling.

(c) Appendix II Engine Maintenance and Surveillance Program

In the applicant's letter of June 5, 1986, the applicant committed "to implement the OG M/S recommendations as identified by Revision 2 to the DR/QR Report." A staff audit review of the Maintenance Matrix showed that for Parts B, C, and D of the matrix, various inspection/maintenance frequencies were to be determined by the applicant, and for Part E, the Component Cross Reference Matrix, some engine components would not be inspected in accordance with the Maintenance Matrix. In a letter dated September 18, 1986, the applicant discussed the discrepancies in Part E of the Maintenance Matrix, and committed to perform the M/S inspections on all engine parts.

The inspections for maintenance requirements, whose frequencies were to be determined by the applicant, are not the types of inspections that are done on a frequent basis (daily, weekly, or monthly). These inspections/maintenance would be done on a frequency corresponding to an overhaul period (refueling outage, or 5- or 10-year overhaul) or would be done on the basis of the results of an inspection of an engine component. Therefore, the staff does not require this information for licensing. However, the staff does need the information to ensure that the frequencies are commensurate with common industry inspection frequencies and practices. Therefore, the staff will require this information before full-power operation of the plant.

(3) Conclusions

On the basis of the staff's review of the applicant's actions to implement the Owners Group recommendations and the staff requirements and recommendations specified in NUREG-1216, the staff concludes that all significant issues warranting priority attention on a basis for issuing an operating license have been adequately resolved. Consequently, the staff concludes that the diesel generators will provide a reliable standby source of onsite power in accordance with General Design Criterion 17 (Appendix A to 10 CFR 50). This conclusion is subject to the license conditions detailed below:

1. Changes to the maintenance and surveillance program for the TDI diesel engines, as identified in Shearon Harris SSER No. 4, Section 8.3.1(2)(c), shall be subject to the provisions of 10 CFR 50.59.

   The frequency of the major engine overhauls referred to in the license conditions below shall be consistent with Section IV.1, "Overhaul Frequency," in Revision 2 of Appendix II of the Design Review/Quality Revalidation Report, which was transmitted by letter dated May 1, 1986, from J. George, Owners Group, to H. Denton, NRC.

2. Connecting rod assemblies shall be subjected to the following inspections at each major engine overhaul:

   a. The surfaces of the rack teeth should be inspected for signs of fretting. If fretting has occurred, it should be subjected to an engineering evaluation for appropriate corrective action.

   b. All connecting rod bolts should be lubricated in accordance with the engine manufacturer's instructions and torqued to the specifications of the manufacturer. The lengths of the two pairs of bolts above the crankpin should be measured ultrasonically pre- and post-tensioning.

   c. The lengths of the two pairs of bolts above the crankpin should be measured ultrasonically before detensioning and disassembly of the bolts. If bolt tension is less than 93% of the value at installation, the cause should be determined, appropriate corrective action should be taken, and the interval between checks of bolt tension should be reevaluated.

   d. All connecting rod bolts should be visually inspected for thread damage (e.g., galling), and the two pairs of connecting rod bolts above the crankpin should be inspected by magnetic particle testing (MT) to verify the continued absence of cracking. All washers used with the bolts should be examined visually for signs of galling or cracking, and should be replaced if damaged.

e. Visual inspection should be performed of all external surfaces of the link box to verify the absence of any signs of service-induced distress.

f. All of the bolt holes in the link rod box should be inspected for thread damage (e.g., galling) or other signs of abnormalities. In addition, the bolt holes subjected to the highest stresses (i.e., the pair immediately above the crankpin) should be examined with an appropriate nondestructive method to verify the continued absence of cracking. Any indications should be recorded for engineering evaluation and appropriate corrective action.

3. The cylinder blocks shall be subjected to the following inspections at the interval specified in the inspections:

a. Cylinder blocks shall be inspected for "ligament" cracks, "stud-to-stud" cracks, and "stud-to-end" cracks as defined in a report* by Failure Analysis Associates, Inc. (FaAA) entitled, "Design Review of TDI R-4 and RV-4 Series Emergency Diesel Generator

Cylinder Blocks" (FaAA report no. FaAA-84-9-11.1) and dated December 1984. (Note that the FaAA report specifies additional inspections to be performed for blocks with "known" or "assumed" ligament cracks.) The inspection intervals (i.e., frequency) shall not exceed the intervals calculated using the cumulative damage index model in the subject FaAA report. In addition, inspection method shall be consistent with or equivalent to those identified in the subject FaAA report.

b. In addition to inspections specified in the aforementioned FaAA report, blocks with "known" or "assumed" ligament cracks (as defined in the FaAA report) should be inspected at each refueling outage to determine whether or not cracks have initiated on the top surface exposed by the removal of two or more cylinder heads. This process should be repeated over several refueling outages until the entire block top has been inspected. Liquid-penetrant testing or a similarly sensitive nondestructive testing technique should be used to detect cracking, and eddy current testing should be performed as appropriate to determine the depth of any cracks discovered.

c. If inspection reveals cracks in the cylinder blocks between stud holes of adjacent cylinders ("stud-to-stud" cracks) or "stud-to-end" cracks, this condition shall be reported promptly to the NRC staff and the affected engine shall be considered inoperable. The engine shall not be restored to "operable" status until the proposed disposition and/or corrective actions have been approved by the NRC staff.

---

*This report was transmitted to H. Denton, NRC, from C. L. Ray, Jr., TDI Owners Group, by letter dated December 11, 1984.

4. The following air roll test shall be performed as specified below, except when the plant is already in an Action Statement of Technical Specification 3/4.8.1, "Electric Power Systems, A.C. Sources":

   The engines shall be rolled over with the airstart system and with the cylinder stopcocks open before each planned start, unless that start occurs within 4 hours of shutdown. All the engines shall be rolled over with the airstart system and with the cylinder stopcocks open after 4 hours, but no more than 8 hours after engine shutdown and then rolled over once again approximately 24 hours after each shutdown. (In the event an engine is removed from service for any reason other than the rolling over procedure before expiration of the 8-hour or 24-hour periods noted above, that engine need not be rolled over while it is out of service. The licensee shall air roll the engine over with the stopcocks open at the time it is returned to service.) The origin of any water detected in the cylinder must be determined and any cylinder head which leaks because of a crack shall be replaced. The above air roll test may be discontinued following the first refueling outage subject to the following conditions:

   a. All cylinder heads are Group III heads (i.e., cast after September 1980).

   b. Quality revalidation inspections, as identified in the Design Review/Quality Revalidation Report, have been completed for all cylinder heads.

   c. Group III heads continue to demonstrate leak-free performance. This should be confirmed with TDI before deleting the air roll tests.

5. Periodic inspections of the turbochargers shall include the following:

   a. The turbocharger thrust bearings should be visually inspected for excessive wear after 40 non-prelubed starts since the previous visual inspection.

   b. Turbocharger rotor axial clearance should be measured at each refueling outage to verify compliance with TDI/Elliott specifications. In addition, thrust-bearing measurements should be compared with measurements taken previously to determine a need for further inspection or corrective action.

   c. Spectrographic and ferrographic engine oil analysis shall be performed quarterly to provide early evidence of bearing degradation. Particular attention should be paid to copper level and particulate size which could signify thrust bearing degradation.

6. Before restart following the first refueling, the engine base shall be inspected for degenerate microstructure (Widmanstatten graphite) and the results shall be submitted to the NRC for evaluation.

7. Before full-power operation of Shearon Harris, the licensee shall provide the NRC with the following:

a. The status of the Phase II component inspections. Any Phase II inspection that has not been completed by full-power operation shall be completed by restart following the first refueling.

b. The inspection frequencies in the maintenance matrix that are to be determined by the licensee.

Physical Independence of Redundant Safety-Related Systems

The applicant had committed to meet the requirements of Regulatory Guide (RG) 1.75 as stated in Section 8.3.1.2.14 of the FSAR. The Shearon Harris electrical raceway system design was based on the standard separation criteria contained in IEEE 384-1974 as endorsed by RG 1.75. These documents provide two options for establishing plant-specific separation criteria, i.e., (1) use guideline separation criteria given in the documents (IEEE 384-1974 as endorsed by RG 1.75) or (2) provide an analysis based on a test program to justify lesser separation than specified by the guideline criteria. FSAR Table 8.3.1-10, "Minimum Separation Distances," presently indicates that Shearon Harris utilized the minimum 1-inch separation criteria between rigid steel conduits and between rigid steel conduits and free air cabling. However, the applicant has proposed a revised separation criteria with values less than the 1-inch minimum as delineated in FSAR Table 8.3.1-10, for separation between rigid steel conduits and between rigid steel conduits and free air cabling.

The applicant requested approval of the revised separation criteria in a submittal dated September 16, 1986 (NLS-86-347). The submittal includes the revised criteria, the results of a test program, and other supporting information. The test program was conducted for the applicant by Wyle Laboratories and documented in Wyle Test Report No. 47879-06.

In addition to the revised separation criteria, the submittal also contained FSAR amendments pertaining to the installation of barriers (FSAR Section 8.3.1.2.30.b.1.a.3). These amendments describe suitable barriers which meet the intent of IEEE 384-1974 and are listed under insert "A" included with the submittal.

- Test Program Results

  Tests were conducted by the Wyle Laboratories for the applicant to justify reduced separation between rigid steel conduits, and between rigid steel conduit and free air cabling as previously approved by the staff and documented in a staff safety evaluation dated February 15, 1986. Before initiating the testing phase of the program, the applicant and Wyle Laboratories personnel developed Test Procedure 47879-05, which formed the basis of the tests. In order to perform a test program to verify the adequacy of the raceway separation criteria, Test Procedure 47879-05 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.

(4) No credit has been taken for operator initiated action to clear the fault.

All cables used in the test program were qualified to meet the requirements of IEEE 383-1974 and were provided to Wyle Laboratories from the Shearon Harris stock. The test specimens consisted of Triplex 350 MCM and 3-1/C 10 AWG as fault cables and twisted pair 16 AWG as the target cables installed into various configurations for the purposes of these tests. These tests consisted of three individual tests between parallel rigid steel conduits and/or free air cables mounted 1/4 inch apart or in contact at a point when crossing. The fault was assumed to occur between the supply panel and the connected load.

In test 1, a fault current magnitude of 180 amperes was used for control cable (3-1/C 10 AWG) 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 the target cables. The purpose of test 1 was to demonstrate the acceptability of raceway design where a control or instrumentation (low energy) conduit is in contact with another raceway or cable requiring separation.

In tests 2 and 3, fault current magnitudes of 3570 and 3550 amperes, respectively, were used for the low-voltage (600 V) power cable tests. In these tests it was assumed that Triplex 350 MCM cable was the worst-case cable because it sustained the worst-case fault. The purpose of tests 2 and 3 was to demonstrate the following:

(1) The acceptability of design where a rigid conduit passes 1/4 inch horizontally or vertically away from a rigid conduit containing the worst-case power-type cable fault.

(2) The acceptability of a design where a free air cable is physically separated by 1/4 inch horizontally from a rigid conduit containing the worst-case power-type cable fault.

(3) The acceptability of design where a rigid conduit touches, at a point, a second rigid conduit containing the worst-case power-type cable fault.

Before the beginning of each cable overcurrent (fault) test, baseline tests of target cable were performed. These consisted of insulation resistance measurements and a 1-minute ac 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-minute ac high-potential test. The acceptability of the raceway design was based upon the condition that the target cable pass the post overcurrent tests, as well as show no physical damage to it.

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

(1) 0-inch separation (in-contact) between a free air cable and a 1-inch rigid conduit containing a low-energy cable, when the worst-case electrical fault occurs in the conduit

(2) 1/4-inch vertical separation between any two parallel rigid conduits when the worst-case electrical fault occurs in the lower conduit

(3) 1/4-inch horizontal separation between any two parallel rigid conduits when the worst-case electrical fault occurs

(4) 0-inch separation (in-contact) between any two rigid conduits in a perpendicular crossing situation when the worst-case electrical fault occurs

(5) 1/4-inch horizontal separation between a free air cable and a perpendicular rigid conduit when the worst-case electrical fault occurs in the conduit

The fault currents selected for the test programs encompass the conditions which 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 cables. The postulated fault current is reasonable, based on the design of the overcurrent protection and electric power supplies. The staff has concluded that the test program with the above assumption and input are acceptable and that the test results proved the acceptability of the proposed separation by meeting the acceptance criteria.

Installation of Barriers

The installation of barriers is described in FSAR, Section 8.3.1.2.30.b.1.a.3. The FSAR guideline criterion for minimum separation distance between barriers and raceway/cables is 1 inch. The applicant, in its submittal of September 16, 1986, under insert "A," described steel tray covers, firewrap, and fire blanket as suitable barriers which meet the intent of IEEE 384-1974.

The steel tray covers are utilized to protect any raceway/cable which extends into the area of separation concern of the tray. A top cover is used to protect above the tray and/or a bottom cover is used to protect below the tray. The steel tray covers are not qualified for a given fire rating such as 1 or 3 hours. The staff assumes that these steel tray covers would be utilized in the same manner as described in IEEE 384-1974 as endorsed by RG 1.75. Therefore, the 1-inch minimum separation distance between the barriers and raceway/cables, as already delineated in FSAR Section 8.3.1.2.a.30.b.1.a.3, will be maintained for the installation of covered cable trays at Shearon Harris.

The firewrap and fire blanket barriers are tested and qualified in accordance with American Society for Testing and Materials Standard ASTM E-119 for a fire rating of 1 or 3 hours. The staff has been assured by the applicant that the firewrap and fire blanket used for raceway installation at Shearon Harris have been tested and qualified in accordance with Standard ASTM E-119. A cable is firewrapped to protect any raceway/cable which converges within the separation window of the cable. Fire blankets of 1-hour and 3-hour ratings are installed to meet the requirements of FSAR Section 9.5.1. The cable-induced fire test results (tests 1, 2, and 3) have indicated that the faulted cable open-circuits after several minutes, thereby limiting the energy let-through of fault current below the setting of the backup device and with assumed failure of the primary protective device. Without assumed failure of the primary protective device and/or currents within the range of backup protective device, most faults would be removed in a matter of seconds by either protective device. Since the firewraps and fire blankets are qualified for 1-hour and 3-hour fire ratings, they have the thermal capability to withstand and protect the raceway system from cable-induced fires. Therefore, the staff has concluded that the 1-inch separation criterion delineated in the FSAR Section 8.3.1.2.30.b.1.a.3 between fire blankets and raceways is not required.

Conclusions

The staff has reviewed the application of the test results to the raceway separation criteria as amended in FSAR Table 8.3.1-10, "Minimum Separation Distances," attached to the letter dated September 16, 1986 (NLS-86-347). On the basis of the staff's review of the applicant's test results, the staff finds acceptable the justification for the deviations from the criteria of RG 1.75 and the revised separation criteria. 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 nor modify the 10 CFR 50 Appendix R criteria, which address exposure fires.

The staff also has assessed the thermal capability of firewraps and fire blankets for protection of raceways from cable-induced fires. The firewraps and fire blankets have been tested for 1-hour and 3-hour ratings by the applicant in accordance with Standard ASTM E-119 for use at Shearon Harris. The staff concludes that no minimum separation guideline criterion is required between blankets and protected raceways. On the basis of the staff's evaluation of the applicant's submittal, the proposed FSAR amendments as delineated under insert "A" are acceptable.

## 8.4 Other Electrical Features and Requirements for Safety

### 8.4.2 Adequacy of Station Electric Distribution System Voltages

#### 8.4.2.1 Position 1--Second-Level Undervoltage

In the SER the staff stated:

> The first level of protection is set to drop out at 72% (72% of the nominal bus voltage is equivalent to 75% of the motor voltage) of 6.9-kV with a time delay of 0.5 second. When these relays sense a

loss of voltage and after 0.5-second delay, they automatically disconnect the offsite source from the Class 1E buses, start the diesel generator, and load shed the bus. When the diesel generator has attained rated speed and voltage (10 seconds) the diesel generator incoming breakers to Class 1E buses are closed and the Class 1E loads are sequenced on the bus.

The second level of undervoltage protection scheme is set to drop out at 89% of 6.9-kV with two definite time delays of 15 seconds and 60 seconds. At the end of the 15-second delay (which is long enough to accommodate the starting of the motor that has the longest starting time), an alarm is actuated at the main control room. A safety injection signal following the 15-second delay will immediately separate the Class 1E loads from the offsite power system. In the absence of an accident signal, a second delay of 60 seconds is allowed before the automatic tripping actions are initiated. This delay is based on the maximum time for which the most sensitive load can perform its safety function without impairment at the degraded voltage.

Subsequently, during the Technical Specification (TS) development process, the applicant revised the above values and reflected them in TS Table 3.3-4 as follows:

| Functional Unit | Trip Setpoint |
|---|---|
| Loss-of-Offsite Power | ≥ 4830 V with a ≤ 1.0-second time delay |
| (a) 6.9-kV Emergency Bus Undervoltage--Primary | ≥ 6420 V with a ≤ 16-second time delay (with safety injection) |
| (b) 6.9-kV Emergency Bus Undervoltage--Secondary | ≥ 6420 V with a ≤ 54.0-second time delay (without safety injection) |

The values provided in the Technical Specifications are conservative with respect to the accident analyses assumptions provided in FSAR Table 15.0.6-1. The staff considers the values provided in the Technical Specifications acceptable.

8.4.8 TMI Action Plan Requirements

Item II.E.3.1, Pressurizer Heater Power Supply

In SER Section 8.4.8, the staff stated that "Westinghouse has determined that 400 kW of pressurized heater capacity is needed to maintain natural circulation in a hot standby condition when offsite power is lost." Subsequently, it was determined that a heater capacity of 250 kW would be sufficient to achieve natural circulation at hot standby. The Shearon Harris design provides two Class 1E pressurizer heater groups, each rated at 432 kW. However, the Westinghouse requirement is that a minimum of 250 kW (two groups each with a minimum of 125 kW) of pressurizer heater capacity is required to maintain natural circulation in a hot standby condition. These values are reflected in the Shearon Harris Technical Specification 3.4.4 and FSAR Section 8.3.1.2.35. The staff concludes that the pressurizer heater capacity provided at Shearon Harris is acceptable.

# 9 AUXILIARY SYSTEMS

## 9.1 Fuel Storage and Handling

### 9.1.5 Overhead-Heavy-Load-Handling System

NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," published in July 1980, provided the results of the staff's review of the handling of heavy loads under generic Task A-36, "Control of Heavy Loads Near Spent Fuel." Following the issuance of NUREG-0612, a generic letter, dated December 22, 1980, was sent to all operating plants, applicants for operating licenses, and holders of construction permits requesting that responses be prepared indicating the degree of compliance with the guidelines of NUREG-0612. The applicant reviewed provisions at Shearon Harris Unit 1 for the handling and control of heavy loads to determine the extent to which the guidelines of NUREG-0612 are being satisfied. By submittals dated June 26 and September 23, 1981; September 19, 1983; March 28, 1985; and June 2, 1986, the applicant responded to the generic letter.

The staff and its consultant, the Idaho National Engineering Laboratory (INEL), have reviewed the applicant's submittals. INEL documented its review in the Technical Evaluation Report (TER) which is reproduced here as Appendix K. The TER identified an open item regarding special lifting devices. By letter dated June 2, 1986, the applicant discussed the design and performance capability of two special lifting devices - an internals lifting rig and the spent fuel storage rack lifting rig. The applicant stated that these specially designed lifting devices have been designed, fabricated, and load tested in accordance with the guidelines of NUREG-0612 and ANSI Standard N14.6. The staff finds the applicant's statement responds to the concern expressed in the TER.

The applicant has also responded to a staff concern regarding the failure of heavy loads attachment points for such components as the reactor coolant pump motors hatch covers. The applicant stated that these components are designed with a minimum safety factor of 3 based on ultimate strength of concrete. Furthermore, the movement of these structures during refueling follows safe load paths in accordance with station procedures to preclude dropping heavy loads on safety-related equipment. Therefore, adequate protection is provided against damage to the fuel from postulated load handling events. The staff finds the applicant's response to this concern to be acceptable.

The staff has reviewed the INEL TER and concurs with its findings. The TER is considered to be a part of this safety evaluation. On the basis of the foregoing discussion on the resolution of staff concerns, the staff concludes that the guidelines of NUREG-0612, Section 5.1.1, have been satisfied. Therefore, Phase I recommendations of NUREG-0612 to be implemented to ensure the safe handling of heavy loads are acceptable. In addition, the staff concludes that no further action is required concerning the Phase II recommendations of NUREG-0612.

## 9.2 Water Systems

### 9.2.2 Primary Component Cooling Water System

In Section 9.2.2 of the SER the staff stated

> The applicant must provide Technical Specifications that include periodic testing of all of the safety-related portions of the CCW system as a unit with all valves operating to isolate non-safety-related loads and with two component cooling water pump trains starting to serve the safety-related loads upon a suitable initiating signal. The applicant should propose such a surveillance test requirement in the Technical Specifications to be performed every 18 months during shutdown. The staff will review the Technical Specifications to ensure this is included. Thus, the CCW system will comply completely with GDC 46.

The staff has completed its review of the above requirements and finds that they have been satisfied and have been incorporated into Section 4.7.3 of the Technical Specifications; thus, this issue has been resolved.

### 9.2.7 Essential Services Chilled Water System

In the SER, the staff concluded that the essential services chilled water system (ESCWS) complied with the criteria of Standard Review Plan (SRP) Section 9.2.2 and was, therefore, acceptable. Subsequently, in response to a series of questions from the Advisory Committee on Reactor Safeguards (ACRS), the staff conducted a physical walkdown of the ESCWS at the Shearon Harris site, in order to gain added assurance that the system complies with the applicable criteria of SRP Section 9.2.2.

A major focus of the ESCWS walkdown was to verify the staff's previous conclusions regarding single-failure capability, fire protection design, and protection against pipe failures. The ESCWS is composed of two separate trains, only one of which is required to operate in order to provide sufficient chilled water for cooling essential (safety-related) air handling units. The staff noted that a fire will not cause damage to more than one ESCWS train based upon protection by means specified in Section C.5.b(2), Subsections (a), (b), and (c) of Branch Technical Position (BTP) 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants." This protection consists of separation by 3-hour fire barriers, or by a horizontal distance of 20 feet, or 1-hour fire barriers together with fire detectors and an automatic fire suppression system. In its walkdown, the staff observed no areas where a high-energy line was close enough to the ESCWS to damage it. Further, a moderate-energy-line break in one ESCSW train would not adversely affect the other ESCWS train; breaks in other moderate-energy lines would not adversely affect either ESCWS train. Thus, the ESCWS safety function is maintained.

On the basis of its walkdown observations, which identified no deviations from the licensing criteria, the staff concludes that its previous acceptance of the ESCWS against the criteria of SRP Section 9.2.2 is still valid, and the system is therefore, acceptable.

## 9.3 Process Auxiliaries

### 9.3.2 Process Sampling System

#### 9.3.2.2 Postaccident Sampling System

In the SER, the staff concluded that the applicant's proposed postaccident sampling system (PASS) partially met the criteria of TMI Action Plan Item II.B.3 (NUREG-0737). As a result, the staff proposed the following license condition:

> Prior to exceeding 5% power operation, Carolina Power & Light Company shall have installed and operational the postaccident sampling system.
>
> Prior to 5% power operation, the applicant: (1) shall submit for NRC approval a core damage assessment procedure which incorporates, as a minimum, hydrogen levels, reactor coolant system pressure, core exit thermocouple temperatures and containment radiation levels in addition to radionuclide data; (2) shall demonstrate applicability of procedures and instrumentation in the postaccident water chemistry and radiation environment, and retraining of operators on semiannual basis; (3) shall provide the plant procedures for chemical analyses and shall provide the accuracy, range, and sensitivity of each of the radionuclide and chemical analyses.

By letters dated July 3 and 6, 1984; May 13 and September 10, 1985; and May 19, 1986, the applicant provided additional information on the proposed postaccident sampling system.

The applicant provided a procedure for estimating the extent of reactor core damage that is based on the measurement of radioactive fission product concentrations in the reactor coolant and containment atmosphere. The procedure also takes into consideration other physical parameters as indicators of reactor core damage, such as the hydrogen concentration in the containment atmosphere, the core exit thermocouple temperature, and the containment atmosphere radiation levels. The staff finds that these provisions meet Criterion (2) in Item II.B.3 of NUREG-0737 and are, therefore, acceptable.

The accuracies, ranges, and sensitivities of the PASS instruments and analytical procedures are consistent with the recommendations of Regulatory Guide 1.97, Revision 3, and the clarifications of NUREG-0737, Item II.B.3, "Post-Accident Sampling Capability." Therefore, they are adequate for assessing the radiological and chemical status of the reactor coolant. The instrumentation was selected for its ability to operate in the postaccident sampling environment. Equipment used in postaccident sampling and analysis will be calibrated or tested at least once every six months. Retraining of operators for postaccident sampling is scheduled at a frequency of once every six months. The staff finds that these provisions meet Criterion (10) in Item II.B.3 of NUREG-0737 and are, therefore, acceptable.

The applicant provided a schematic diagram of the postaccident sample lines and sampling panels, as required by Item II.B.3 (NUREG-0737).

On the basis of the above evaluation, the staff concludes that the applicant's proposed postaccident sampling system meets all the criteria in Item II.B.3 of NUREG-0737 and is, therefore, acceptable. The previously proposed license condition on the postaccident sampling system has been removed.

## 9.5 Other Auxiliary Systems

### 9.5.1 Fire Protection

In SER Supplement 3, the staff indicated that its review of the applicant's fire protection program for Shearon Harris was complete. By letters dated May 7, June 4, June 18, June 20, July 22, and August 6, 1986, the applicant provided additional information (including Revision 3 to its point-by-point comparison with BTP CMEB 9.5-1), requests for additional deviations from BTP CMEB 9.5-1, and FSAR Amendment 27.

The information provided contained changes resulting from continued program development, and incorporated information previously provided via docketed correspondence, editorial changes, and clarifications. Only those changes that affect the staff's previous safety evaluations are addressed in this supplement.

#### 9.5.1.1 Fire Protection Program Requirements

Fire Protection Program

Generic Letter 86-10, "Implementation of Fire Protection Requirements," dated April 24, 1986, states that inclusion of the fire protection program into the FSAR is a prerequisite for licensing for all applications now under review. By letter dated July 22, 1986, the applicant submitted, as Attachment 2, Insert 1 to FSAR page 9.5-1. This insert (1) incorporates the fire protection program that has been approved by the staff, including the Fire Protection Evaluation and Comparison to BTP CMEB 9.5-1 and Safe Shutdown Analysis in Case of Fire that form the basis of the fire protection program,* into the FSAR by reference, and (2) includes a commitment to establish limiting conditions for operation, action statements, and surveillance requirements for the fire protection program within the Shearon Harris Plant Operating Manual. The applicant stated that these procedures will provide a level of protection equivalent to the fire protection sections of the Westinghouse Standard Technical Specifications.

This revision to Section 9.5-1 of the Shearon Harris FSAR meets the guidance for operating license applications currently under review as set forth in Generic Letter 86-10. On this basis and on the basis of the applicant's commitment, the staff finds the FSAR revision submitted by the applicant in its July 22, 1986, letter acceptable.

#### 9.5.1.4 General Plant Guidelines

Building Design

Section C.5.a of BTP CMEB 9.5-1 states that flexible air duct coupling in ventilation and filter systems should be noncombustible. In Revision 3 to the

*The fire hazards analysis is currently included in the FSAR as Appendix 9.5A.

comparison with BTP CMEB 9.5-1, the applicant informed the staff that combustible flexible air duct coupling is utilized in ventilation and filter systems at Shearon Harris. The applicant conservatively estimated that this combustible material constitutes less than 1.5% of the total ductwork footage and that there are no large concentrations of the material in any plant area. On the basis of its limited use, the staff concludes that the combustible flexible duct couplings will not contribute appreciably to the spread of fire. This is, therefore, an acceptable deviation from Section C.5.a of BTP CMEB 9.5-1.

In the SER, the staff stated that floor drains are provided to remove fire-fighting water from areas containing safety-related equipment, and to prevent excess fire-fighting water from flooding areas containing safety-related equipment. The SER should be amended to read that floor drains are provided in areas in which fixed water suppression systems and hoses are installed, except for areas having natural drainage. This meets Section C.5.a of BTP CMEB 9.5-1 and is, therefore, acceptable.

The guidelines of Section C.5.a of BTP CMEB 9.5-1 state that fire barriers with a minimum fire resistance rating of 3 hours should be provided to separate redundant divisions of safety-related equipment. By letter dated June 18, 1986, the applicant requested a deviation from these guidelines for certain penetration openings through fire barriers for ventilation systems, doors, and bus ducts to the extent that the penetrations are not protected with equivalently rated fire damper assemblies, door assemblies, or seals, respectively. The locations of the penetrations are identified in Tables 1, 2, and 3 which are appended to the June 18, 1986 letter.

Within 20 feet of each penetration and door where safe shutdown equipment is located, automatic suppression and detection has been provided on at least one side of the penetration or door. In addition, redundant safe-shutdown-related components are separated by at least 20 feet.

The staff was concerned that a fire originating in one fire area would spread through an unprotected fire barrier penetration into an adjacent fire area, damage redundant safe-shutdown systems, and adversely affect the plant's safe-shutdown capabilities. However, the staff reviewed and evaluated conditions on each side of each penetration and found no significant unmitigated fire hazards that pose a credible threat to redundant safe-shutdown systems.

Because of the fire detectors provided, the staff expects any fire to be detected before redundant safe-shutdown-related systems are threatened. The fire brigade would then take action to extinguish the fire. In the unlikely event that the fire spreads from one area to another through one of the penetrations, the automatic suppression system will actuate and control the spread of fire. Until the fire suppression system operates, the physical separation of redundant systems is sufficient to provide reasonable assurance that one shutdown division would remain free of fire damage. On the basis of its review, the staff concludes that upgrading the subject fire barrier penetrations to achieve a 3-hour fire resistance rating would not significantly increase the level of fire safety. The fire barrier penetrations identified in the applicant's June 18, 1986, letter are, therefore, an acceptable deviation from Section C.5.a of BTP CMEB 9.5-1.

Safe-Shutdown Capability

By the June 18, 1986, letter, the applicant also requested a deviation from Section C.5.b of BTP CMEB 9.5-1 to the extent that the intervening space between component cooling water (CCW) pumps 1A-SA and 1B-SB and their related cables is not free of intervening combustibles.

The CCW pumps, which are located on the 236-foot elevation of the reactor auxiliary building (fire area 1-A-BAL), are separated by more than 100 feet. The intervening combustibles located between the pumps consists of IEEE Std 383 cables in cable trays. The general arrangement of the pumps and cable trays is shown in Figure 1 of the June 18, 1986, letter. The SB cable tray is located 11 feet from CCW pump 1B-SB and 8 feet from the SA cable tray. The SA cable tray is located about 20 feet from CCW pump 1B-SB. The location is provided with automatic fire detection and suppression capabilities. The staff was concerned that a fire could spread to redundant divisions via the intervening cable trays. However, for a fire to damage the redundant CCW pumps, an exposure fire in the vicinity of CCW pump 1B-SB, for example, would have to damage CCW pump 1B-SB and its power or control cables, ignite the intervening cable trays, propagate more than 100 feet along the intervening trays, and then damage CCW pump 1A-SA or its power or control cables. In the staff's opinion, this scenario is unlikely because the ignition and flame spread resistances of the IEEE Std 383-qualified cables installed at Shearon Harris and the presence of automatic detection and suppression capabilities. The staff concludes, therefore, that there is reasonable assurance the intervening cables will not contribute to the loss of safe-shutdown capability in the event of a fire in fire area 1-A-BAL. This is, therefore, an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1.

In SER Supplement 3, the staff stated that in the event of a control room fire requiring evacuation of the control room and use of the auxiliary control panel (ACP) to effect shutdown, two operators are sufficient to accomplish post-fire shutdown from the ACP. However, by letter dated August 6, 1986, the applicant stated that five operators are needed to coordinate the shutdown effort. This number of operators is specified in the Technical Specifications. The staff finds this acceptable.

The staff also stated in SER Supplement 3 that breaker coordination will be tested every 18 months to ensure that overall coordination between the load feeder breakers and bus feeder breakers remains within design limits. By letter dated August 6, 1986, the applicant quantified the level of testing that would be done. The periodic testing to be performed will consist of verifying protective relay setpoints of at least 10% of the 480-V breakers included in the safe-shutdown analysis. Further, for each breaker found inoperable, an additional 10% of the protective relays of the inoperable type will be tested until no other failures occur, or all relays of that type have been tested. The molded case circuit breakers that supply penetrations will continue to be tested as required by the Technical Specifications. The staff considers this scope of testing to be acceptable.

9.5.1.5 Fire Detection and Suppression

In the SER, the staff stated that standpipe system piping for hose stations protecting safe shutdown equipment has been analyzed for safe-shutdown-earthquake (SSE) loading and is provided with seismic supports in accordance with Section C.6.c of BTP CMEB 9.5-1. In fact, this is not the case for the diesel generator building, the diesel fuel oil storage building, and the emergency service water intake structures. By letter dated August 25, 1986, the applicant justified this deviation from staff guidelines.

On the basis of its review of the applicant's justification, which is based on the separation of the redundant safe-shutdown equipment located in the diesel generator building, the diesel fuel oil storage building, and the emergency service water (ESW) intake structure by seismic Category I 3-hour fire rated barriers, and the provision of alternative means of manual firefighting, the staff concludes that the standpipe system is acceptable. The lack of seismically qualified hose stations in the diesel generator and fuel oil storage buildings and the emergency service water (ESW) intake structure is an acceptable deviation from Section C.6.c of BTP CMEB 9.5-1.

### 9.5.1.6 Fire Protection of Specific Plant Areas

#### Containment

Section C.7.a of BTP CMEB 9.5-1 states that self-contained breathing apparatus (SCBA) should be provided near the containment entrances during refueling and maintenance operations for fire-fighting personnel. In Revision 3 to the comparison to BTP CMEB 9.5-1, the applicant informed the staff that the SCBA is maintained at a central location in the turbine building. Because the fire brigade will assemble at this central location to collect the fire-fighting equipment before proceeding to the fire scene, the staff finds this arrangement acceptable.

#### Control Room

In SER Supplement 2, the staff stated that there are no raised floors in the control room. In Revision 3 to the comparison to BTP CMEB 9.5-1, the applicant informed the staff that a raised floor has been created in the control room. Section C.7.b of BTP CMEB 9.5-1 states that area automatic fire suppression should be provided for underfloor spaces if used for cable runs.

The raised floor section is located in front of the main control panels and has two computer cathode-ray tubes (CRTs) mounted on the raised section. Seven low-voltage signal cables and one 120-V power cable are located under the raised section. Ionization detectors are installed under the raised floor. Area automatic fire suppression is not provided.

Because of the negligible fuel loading under the raised floor in concert with the installed early-warning smoke-detection capability and continuous manning of the control room, the staff finds the omission of a suppression system in the raised section an acceptable deviation from Section C.7b of BTP CMEB 9.5-1.

The applicant also informed the staff that carpeting will be installed in the control room. The carpeting will be noncombustible in accordance with Section C.5.a(9) of BTP CMEB 9.5-1. On this basis, the staff concludes that the installation of carpeting in the control room is an acceptable deviation from Section C.7.b of BTP CMEB 9.5-1.

Switchgear Rooms

In the SER, the staff stated that floor drains have been provided in the switchgear rooms. In fact, drains have not been provided. However, in the event of a fire requiring the use of a manual hose station, the applicant stated that accumulated water can migrate to adjacent areas equipped with floor drains. Drainage into the adjacent areas will not damage safety-related equipment. In addition, curbing is installed to keep the redundant switchgear room from flooding. This meets Section C.7.e of BTP CMEB 9.5-1 and is, therefore, acceptable.

Remote Safety-Related Panels

In the SER, the staff stated that panels providing remote shutdown capability are located in the auxiliary control panel room, which is separated from other plant areas by barriers having a fire resistance rating of 3 hours. The SER should be amended to read that the panels providing remote shutdown capability are remote from the control room and separated from other plant areas by barriers having a fire resistance rating of 3 hours. This change does not affect the staff's SER finding.

9.5.1.7 Summary of Approved Deviations From BTP CMEB 9.5-1

On the basis of the above evaluation, the staff has concluded that the following deviations from BTP CMEB 9.5-1 are acceptable:

- limited use of combustible flexible air duct couplings as described in Section 9.5.1.4 above

- lack of fire-rated fire damper assemblies, door assemblies, and penetration seals in certain fire areas as described in Section 9.5.1.4 above

- presence of intervening combustibles between the redundant component cooling water pumps as described in Section 9.5.1.4 above

- lack of a fire suppression system in the control room raised floor as described in Section 9.5.1.6 above

- carpet in the control room as described in Section 9.5.1.6 above

- lack of seismically qualified fire hose stations in certain areas as described in Section 9.5.1.5 above

Previously approved deviations from the guidelines of BTP CMEB 9.5-1 are listed in the Shearon Harris SER, SER Supplement 2, and SER Supplement 3.

9.5.1.8 Conclusion

On the basis of its review, the staff concludes that the fire protection program, with approved deviations, meets BTP CMEB 9.5-1, satisfies General Design Criterion (GDC) 3 of Appendix A to 10 CFR 50, and is, therefore, acceptable.

The staff will condition the operating license (see below) to require that the applicant implement and maintain in effect all provisions of the approved fire protection program.

> The licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report, for the facility, and as approved in the SER (NUREG-1038) dated November 1983 and its Supplements, subject to the following provision:
>
> The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

### 9.5.4 Emergency Diesel Engine Fuel Oil Storage and Transfer System

#### 9.5.4.2 Emergency Diesel Engine Fuel Oil Storage and Transfer System

In Section 9.5.4.2 (pp. 9-62 to 9-66) of the SER, the staff stated that "The fuel oil quality and tests will conform with RG 1.137, 'Fuel Oil Systems for Standby Diesel Generators,' Positions C.2.a through C.2.h." However, the applicant has taken exception to the explicit guidance of RG 1.137. The staff has reviewed the applicant's test methods for ensuring that they maintain a high quality fuel oil and has reviewed Section 4.8.1.1.2 of the Technical Specifications and finds them aceptable. The staff considers this issue resolved.

# 10 STEAM AND POWER CONVERSION SYSTEM

## 10.4 Other Features

### 10.4.9 Auxiliary Feedwater System

In SER Section 10.4.9, the staff stated that it would report on two Technical Specification issues regarding the auxiliary feedwater (AFW) system, in a supplement to the SER.

The first issue is that the applicant's proposed Technical Specifications did not address allowable outage times for two and three inoperable AFW pumps. The staff required that such a specification be provided for compatibility with the Westinghouse Standard Technical Specifications (STS). The applicant has now done this, and the specification describes that with two inoperable AFW pumps, the plant must be in at least hot standby within 6 hours and in hot shutdown within the following 6 hours; with three pumps inoperable, immediate corrective action must be initiated to restore at least one AFW pump to operable status as soon as possible. The staff concludes that the proposed specification is acceptable since it is in conformance with the STS and satisfies the staff position identified in the SER.

The second issue identified in the SER concerns the staff's position that a specification be provided requiring flow testing of the AFW system before startup after any extended cold shutdown to verify the normal AFW system flow path from the condensate storage tank to the steam generators. The intent of the specification is to ensure at least one flow path to the minimum number of steam generators, and operation of only one pump is sufficient to meet this requirement; however, because the AFW system at Shearon Harris will be used during startup from cold shutdown through hot standby (motor-driven pumps only) and this will verify the flow path, such a specification is not necessary. This approach is consistent with the Westinghouse STS as well as the staff position on other pressurized-water reactors which use the AFW system for startup. Technical Specification Issues 25 and 26 are now closed (SER Section 16).

# 11 RADIOACTIVE WASTE MANAGEMENT

## 11.5 Process and Effluent Radiological Monitoring and Sampling Systems

### 11.5.2 Evaluation and Findings

The SER included two items on the process and effluent monitoring system that had not been addressed by the applicant. These two items are:

(1) sampling frequencies, required analyses, instrument alarm/type setpoints, calibration, and sensitivities

(2) frequency of routine instrument calibration, maintenance, and inspections

The applicant has addressed these two items to the satisfaction of the staff through the Radiological Effluent Technical Specifications (RETS) and the related Technical Specification Issue 27 on these two items is closed.

# 13 CONDUCT OF OPERATIONS

## 13.1 Organizational Structure of Applicant

The staff's evaluation of the applicant's organizational structure is provided in SER Section 13.1. One confirmatory item and one license condition were identified in the SER. In accordance with Commission Order CLI-80-12, dated April 17, 1980, the staff performed a preliminary assessment of the applicant's organization and management as part of the acceptance review of the operating license application for the Shearon Harris Nuclear Power Plant Units 1 and 2. Results of this review were furnished to the Commission in SECY-81-617, were made available for public inspection in the Commission's Public Document Room, and were placed in the Wake County Public Library, 104 Fayetteville Street, Raleigh, North Carolina.

On the basis of its preliminary assessment, the staff concluded that the proposed organization and management for operation of the Shearon Harris facility, at both the corporate and plant levels, are acceptable. The staff has also reviewed the applicant's final organization and management as part of the staff's detailed review of the application for an operating license. On the basis of its final review, the staff concludes that the organization and management for operation of the Shearon Harris facility at both the corporate and plant levels are acceptable.

Carolina Power and Light Company (CP&L) is responsible for the design, construction, modification, and overall operation of the Shearon Harris plant. CP&L personnel have the benefit of experience gained in the design, construction, modification, operation, training, support engineering, security, and fire protection required at CP&L's three operating nuclear plants; thus, CP&L has a large, experienced technical staff. One of these plants, H. B. Robinson Unit 2, is similar to Shearon Harris even though it is an older design; the other two plants are boiling-water reactors. The entire nuclear organization is shown in Figure 13.1.

### 13.1.1 Corporate Management and Technical Support Organizations

CP&L underwent a major restructuring of the corporate organization in August 1983. Since that time, the NRC has been continuously assessing CP&L's ability to ensure safe operation of its nuclear facilities and the quality of construction and startup of Shearon Harris. These assessments and audits have been carried out by personnel from NRC's Office of Nuclear Reactor Regulation, Office of Inspection and Enforcement, and Region II, as well as by a number of consultants.

The applicant has also recently undergone three successful audits by the Institute of Nuclear Power Operations (INPO) that focused upon training, corporate office support of the nuclear facilities, and the Shearon Harris startup testing program.

The Senior Executive Vice President (SEVP), Power Supply and Engineering and Construction (PSE&C) is the Chief Operating Officer of CP&L and is a member of CP&L's Executive Committee. The SEVP is responsible for ensuring that corporate policies and, in particular, policies regarding nuclear safety are implemented within his organization and for ensuring that the Chief Executive Officer and the Board of Directors are kept advised of matters relating to his group, including nuclear plant operation.

The SEVP is kept abreast of the design, construction, staffing, training, and other aspects of the Shearon Harris facility through reports prepared by the Nuclear Generation Group, and the Corporate Quality Assurance Department. In addition to participating in senior management meetings on a monthly basis, the SEVP also communicates, as required, directly with the group, department, and section managers to receive first-hand information. The SEVP renders the decisions, when required, on any interfaces that may arise between the groups and departments that perform nuclear activities.

13.1.1.1 Nuclear Generation Group

The Nuclear Generation Group (NGG) is under the direction of a Senior Vice President, who reports to the SEVP PSE&C. Three departments and two sections report directly to the Senior Vice President. They are: (1) Harris Nuclear Project Department; (2) Robinson Nuclear Project Department; (3) Nuclear Plant Engineering and Licensing Department; (4) Nuclear Construction Section; and (5) Nuclear Support Staff Section.

The Nuclear Generation Group is responsible for engineering, construction, startup, operations, and maintenance of the company's nuclear plants, except for Brunswick Steam Electric Plant which reports directly to the SEVP PSE&C. The facilities of the NGG include the staff support such as engineering, licensing, and administration. The NGG is shown in Figure 13.2.

13.1.1.1.1 Harris Nuclear Project

The Harris Nuclear Project (HNP) is under the direction of a Vice President who reports to the Senior Vice President NGG. He is responsible for the construction, operations, and maintenance of Shearon Harris. The HNP at present has five Section Managers who report to the Vice President: (1) the General Manager - Engineering, (2) the Plant General Manager, (3) the General Manager - Milestone Completion, (4) Manager - Project Administration, and (5) Manager - Planning and Controls, as shown in Figure 13.2.

13.1.1.1.2 Robinson Nuclear Project

In addition to four other departments that provide support to Shearon Harris, the Manager, Robinson Nuclear Project, reports to the Senior Vice President, Nuclear Generation, and provides technical assistance when needed.

13.1.1.1.3 Brunswick Nuclear Project

The Vice President of the Brunswick Nuclear Project (BNP) reports directly to the SEVP PSE&C. The Vice President BNP is available to provide technical and/or operational assistance to the Senior Vice President NGG and Vice President HNP.

#### 13.1.1.1.4 Nuclear Engineering and Licensing Department

The Vice President of the Nuclear Engineering and Licensing Department, who reports to the Senior Vice President NGG, is responsible for providing engineering support for the company's operating nuclear plants and for managing the company's nuclear licensing activities. This Vice President is also responsible for ensuring that operations and engineering feedback on both internally and externally generated nuclear plant safety issues are incorporated into new plant design and into modifications to operating plants.

The manager of the licensing section who reports to the Vice President directs CP&L licensing activities with NRC for Brunswick, Robinson, and Harris plants; resolves generic licensing activities such as fire protection, equipment qualification, pressurized thermal shock, and emergency response capabilities; provides for an automated commitment tracking system that tracks regulatory commitments, participates in Westinghouse and boiling-water reactor (BWR) owners groups; and maintains contact with such groups as the Edison Electric Institute, the Nuclear Safety Analysis Center, and other utility group activities.

#### 13.1.1.1.5 Nuclear Construction Section

The Manager of the Nuclear Construction Section, who reports to the Senior Vice President NGG, is responsible for providing construction procurement and contracting and construction support on plant modification projects or new plant construction as requested by the Harris, Robinson, and Brunswick Nuclear Project Managers.

#### 13.1.1.1.6 Nuclear Staff Support

The Manager of Nuclear Staff Support, who reports to the Senior Vice President NGG, is accountable for optimizing nuclear operations and supporting the Senior Vice President in meeting department objectives and goals and in department planning, control, coordination, communications, and overall management direction. He does this by providing administrative and technical support; recommending, developing, and implementing policies and procedures; representing the Senior Vice President in meetings with other departments; assisting plant management and others in directing problems to department management levels; carrying out recurring and special projects, often of major scope and importance; representing the department on task forces; managing corporate reporting and response to INPO evaluations and information requests; and ensuring the validity of information and accuracy of reports, presentations, and speeches prepared for the Senior Vice President. This manager is also responsible for effective interface and communication with the news media, regulatory agencies, audit groups, and the public on behalf of the Senior Vice President NGG.

### 13.1.1.2 Operations Support Group

The Operations Support Group (OSG) is under the direction of a Senior Vice President who reports to the SEVP PSE&C. The OSG provides offsite technical and managerial support in areas of nuclear fuel procurement, nuclear safety refueling operation support, plant procurement support, emergency preparedness, operator training, and technical support. This organization is shown in Figure 13.1.

13.1.1.2.1 Materials Management Department

The Manager of Materials Management, who reports to the Senior Vice President OSG, is responsible for the effective management of purchasing, materials control, warehousing, and salvage and disposal of the company's material needs. This manager is responsible for overseeing the activities of the Purchasing and Materials Control Sections.

13.1.1.2.2 Operations Training and Technical Services Department

The Vice President of the Operations Training and Technical Services Department (OTTS), who reports to the Senior Vice President OSG, is responsible for coordinating nuclear plant training for plant personnel, corporate health physics, nuclear fuel activities, and providing other special services and technical expertise.

The Manager of Fuel, who reports to the Senior Vice President OTTS, is responsible for the management of nuclear fuels used for the production of electrical power. This manager is responsible for forecasting, planning, accounting, and procuring nuclear fuel materials in order to meet the company's needs. He is also responsible for providing technical and administrative support to the nuclear plants on fuel-related licensing, regulatory, and other activities.

The Manager of Corporate Health Physics, who reports to the Vice President OTTS, investigates known or suspected radiation overexposures and reports the results through the Vice President OTTS and Senior Vice President OSG to the SEVP PSE&C, including steps that have been taken to prevent similar incidents in the future. He is also responsible for the development, implementation, and maintenance of the corporate as low as reasonably achievable (ALARA) program. The corporate ALARA program defines the scope and requirements for individual ALARA programs for company health physics activities as well as activities that affect health physics programs, such as nuclear plant engineering and construction. The Manager of Corporate Health Physics is also responsible for conducting a periodic management review of CP&L's quality assurance (QA) audit program.

The Manager of the Nuclear Training Section, who reports to the Vice President OTTS, is responsible for providing training support to Nuclear and Fossil Operations Department and all generating plants. This effectively supports corporate requirements for a present and future competent work force, provides for management succession, and maintains a high level of productivity and morale while meeting company and regulatory requirements. This is accomplished by managing the planning, design, development, implementation, and coordination of curriculum development, nuclear and simulator training, fossil operator training, craft and technical training, instructor training, on-the-job training, nuclear plant operator license training, general employee training (GET), shift technical advisor (STA) training, and other training; by managing the operation, maintenance, and expansion of the Shearon Harris Training Center and the training facilities at Brunswick and Robinson; by providing special maintenance support to the Environmental Technology and Environmental and Radiation Control Sections, and by maintaining a skilled training organization to provide and administer a training program of high quality, technical depth, and practical application.

13.1.1.2.3 Nuclear Safety and Environmental Services Department

The Manager of the Nuclear Safety and Environmental Services (NSES) Department, who reports to the Senior Vice President OSG, is responsible for overseeing the management of nuclear safety review at nuclear facilities, coordinating emergency preparedness activities, chemistry, radiological environmental programs, environmental services, and providing technical services and assistance to other departments.

The Manager of Corporate Nuclear Safety, who reports to the Manager NSES, is responsible for the independent assessment of nuclear safety aspects of CP&L's nuclear concerns. He, with his Manager, has the authorized organizational freedom to contact anyone within CP&L, including the Chairman/President of the Board of Directors, to resolve such concerns to their satisfaction. He is responsible for independent review of plant documents and safety analyses as is required by ANSI Standard 18.7, and for review of in-house operating experiences and dissemination of pertinent item for inclusion in the onsite operating experience feedback program. He also is responsible for the evaluation of plant systems to ensure that they meet their design and operational objectives and investigation of special areas of nuclear interest; for the development and application of analyses techniques such as computer engineering codes and probabilistic risk assessment in a nuclear safety review capacity; and for the independent safety engineering group. In addition, there are unit directors on each site who report to the Manager of Nuclear Safety with the responsibilities for: (1) systematic surveillance and assessment of all plant programs and activities that impact safety to ensure that efficient, safe operation is achieved and human errors are kept at a minimum; (2) review of operating experience from within and outside the company and feedback of important information to responsible plant groups for incorporation into training programs, procedures, or design changes as required by Item I.C.5 of NUREG-0737; (3) review of plant transients and safety system challenges to identify "lessons to be learned"; and (4) review of safety-related procedures and plant modifications.

The Manager of the Emergency Preparedness Section, who reports to the Manager - NSES, is responsible for: directing and coordinating corporate emergency planning to ensure regulatory compliance; assessing the readiness of all CP&L emergency plants and programs; serving as interface with regulatory agencies on emergency preparedness matters; providing emergency preparedness support for CP&L nuclear plants; maintaining training qualifications of plant personnel in emergency response; testing emergency preparedness by preparing and conducting exercises; ensuring the availability and operational readiness of emergency facilities, equipment, and supplies; developing dam failure emergency plans for the applicant's hydro plants; and providing coordination with Federal, State and local agencies.

13.1.1.3 Quality Assurance Department

The Manager of Corporate Quality Assurance (CQA), who reports to the SEVP PSE&C, is responsible for the consolidated efforts of quality assurance (QA), quality control (QC), and audit functions. Each nuclear plant site now has onsite QA/QC staff to oversee QA/QC activities for engineering, construction, and operation. The Manager of CQA is also responsible for oversight of QA/QC activities at each of the nuclear plants and oversight of the Quality Assurance Services Section. In this way, the Corporate QA Department Manager oversees the QA/QC activities of both the PSE&C groups while maintaining independence from any responsibilities within those groups.

13.1.1.4 Personnel Qualifications

The applicant has stated that the Manager - Harris Plant Engineering meets the qualification requirements of "engineer-in-charge" as defined in Section 4.6.1 of ANS 3.1 (September 1979 draft). The staff has reviewed the résumés of the individuals filling primary technical support positions and finds that each meets the specified standard for his position and is acceptable.

13.1.1.5 Conclusions

The applicant has described the organization for the management of and the means for providing technical support for the plant staff during operation of the facility. As mentioned in Section 13.1.1, CP&L restructured its organization on August 24, 1983, to take a major step in consolidating nuclear activities within CP&L. Since that time, the applicant's overall management capability has been scrutinized by the Atomic Safety and Licensing Board (ASLB), the Advisory Committee on Reactor Safeguards (ACRS), Office of Inspection and Enforcement (IE), the Office of Nuclear Reactor Regulation (NRR), and Region II.

The ACRS stated:

> CP&L has taken measures to improve management function and capability. The initial restructuring of the corporate organization will eventually result in a consolidation of CP&L's nuclear organization under one Senior Manager. The restructuring also provides for a corporate level executive to be located on site as a member of involved site management to ensure greater access to resources and to enhance the ability to initiate new programs from the site. These efforts are expected to correct the past deficiencies.

The ASLB, in regard to Intervenors Joint Contention 1, reviewed CP&L's management capability to operate the Shearon Harris facility. The ASLB agreed with the applicant and the NRC staff that the findings related to the applicant's management competence demonstrate that CP&L's management structure at both the corporate and plant levels is properly structured to conduct the activities necessary to operate CP&L's nuclear facility safely.

The construction program at Shearon Harris was audited in October and November of 1984 by an NRC Construction Appraisal Team (CAT) composed of members of IE, NRC Region II, and a number of consultants. The results of this inspection indicated evidence of good project management and construction practices. These good practices included a capable project management organization that demonstrated management control of construction activities and the quality of construction.

The engineering program at Shearon Harris was audited between December 1984 and February 1985 by an NRC Independent Design Inspection (IDI) Team composed of members of IE, NRR, and a number of consultants. The team concluded that the plant design process had been adequately controlled.

Additionally, a recent Systematic Assessment of Licensee Performance (SALP) Report demonstrated CP&L's performance was satisfactory and that CP&L continued to demonstrate a proper concern for nuclear safety, both in dedication to safe and reliable plant performance and by having qualified and experienced personnel directing an effective project.

The examples given above bear witness to the fact the NRC finds CP&L's present corporate and plant organizations acceptable to safely operate the Shearon Harris plant.

The following conclusions are based on the criteria of SRP Section 13.1.1 which states: "A corporate officer should clearly be responsible for nuclear activities, without having ancillary responsibilities that might detract from his attention to nuclear safety matters." The only corporate officer responsible for all nuclear activities is the SEVP PSE&C. However, he is also responsible for all fossil generation, transmission, and distribution for the company. Although this does not meet the portion of the guidance stating that the person in charge of nuclear activities shall have no ancillary responsibilities, CP&L has demonstrated that its current organizational structure is adequate. Therefore, the staff finds that the present organization within CP&L is acceptable.

The nuclear training organization is not under the Nuclear Generation Group. It reports to the Operation Support Group where the Group Senior Vice President could become directly involved, when needed, if training were not being determined by the needs of the plant, but rather by a corporate organization. The Group Senior Vice President, Operation Support, has stated and is formulating company policy that site training needs will be determined by the plant with a very strong "dotted line" of reportability to site management. The appointment of a corporate training manager who was previously a Plant General Manager has solidified this policy. The staff finds the reportability of this organization to be acceptable.

The Corporate Nuclear Safety Department has been moved from under the direct responsibility of the SEVP PSE&C to the corporate officer who has primary responsibility for nuclear support activities. Such an arrangement is common industry practice. This arrangement was also suggested by the NRC in the SER. The staff finds this reportability acceptable.

The Brunswick Nuclear Project (BNP) does not, at this time, report to the Nuclear Generation Group as do the other company nuclear projects. The applicant has stated that it intends to move the BNP Department to the Nuclear Generation Group at an appropriate time in the future, based on the status of extensive changes presently under way at BNP. The NRC recognizes the unique situation at BNP and finds the arrangement acceptable.

The staff concludes that CP&L has an appropriate management structure in place and is technically qualified to operate Shearon Harris within the purview of the regulations and with due regard for public health and safety. The Region II inspection and enforcement program will be applied to ensure that CP&L continues to operate within the regulations.

### 13.1.2 Operating Organization

Generic Letter 84-16 specifies that each operating shift have at least one individual who has had at least six months of previous experience on a hot, operating nuclear power plant of a similar type (either PWR or BWR), including startup and shutdown experience, and at least six weeks of experience above 20% power. By letter dated March 20, 1986, the applicant provided additional information about the operators it plans to use during startup operations at the Shearon Harris plant to meet the guidelines of Generic Letter 84-16.

The staff's review of the information provided in the March 20, 1986, letter reveals that three individuals are SRO licensed on Shearon Harris and have had the previous experience on PWRs necessary to meet the guidelines of Generic Letter 84-16. Two individuals possess the requisite experience to meet the generic letter guidelines, but they were still in training for their Senior Reactor Operator (SRO) licenses at the time the March 20, 1986, letter was written. When these two receive their SRO licenses on Shearon Harris, they will fully meet the guidelines. Also, two individuals have SRO experience at BWRs and both were still in training for their SRO licenses on Shearon Harris. At such time as they receive their SRO licenses, they will be qualified to serve as Shift Foremen, but neither of them will meet the guidelines of the generic letter, since their previous experience was on BWRs.

Another individual is SRO licensed on Shearon Harris and has had some previous hot operating experience on a PWR, although it is insufficient to meet the guidelines of the generic letter. However, the applicant has described this man's total qualifications and previous experience and has evaluated him as being a mature and capable operator. The applicant desires to use him to provide the PWR experience background to assist other experienced senior operators now in training for their SRO licenses on Shearon Harris, but who have BWR rather than PWR experience. The staff has examined this individual's total experience as described by the applicant and considers that a shift including either of the BWR-experienced operators and this PWR-experienced operator would be sufficiently qualified to ensure safe plant operations.

In summary, the applicant now has three individuals who are fully qualified to provide the onshift hot operating experience specified by Generic Letter 84-16. Two other individuals will be fully qualified after they receive their SRO licenses on Shearon Harris. These five individuals will be able to provide the coverage on five operating shifts. A sixth shift could be covered by either of the BWR-experienced operators, assisted by the PWR-experienced individual.

Thus, the staff concludes that, subject to the completion of training, the applicant will have a sufficient number of experienced senior operators to provide onshift operating experience meeting the guidelines of Generic Letter 84-16.

The above experience on shift or its equivalent must be in place before exceeding 5% of rated core power.

#### 13.1.2.1 Project Organization

The Harris Nuclear Project (HNP) is under the direction of the Vice President, Harris Nuclear Project Department, who reports to the Senior Vice President Nuclear Generation Group. The HNP organization is shown on Figure 13.2.

Reporting to the Vice President HNP is the Plant General Manager - Harris Plant Operations Section; General Manager - Milestone Completion; General Manager - Harris Plant Engineering Section; Manager - Project Administration; and Manager - Planning and Controls.

13.1.2.2 Plant Operating Organization

The Plant Operations organization chart is shown as Figure 13.3. This figure shows the title of each position, the positions for which reactor operator (RO), or senior reactor operator (SRO) status is required, and the technical support functions for which each group is responsible. This figure will be included in a future revision to the FSAR.

During normal operations, the Plant General Manager - Harris Plant Operations Section, is responsible for all plant activities. In his absence, the Assistant Plant General Manager assumes the authority and responsibilities.

As of April 24, 1986, there were 418 people in the Harris Plant Operations Section organization located on site. All key positions have been filled. The applicant plans to provide five operating shift crews and a sixth shift foreman. As of April 1986, 30 individuals have passed their NRC license examination, 24 are required licensed positions and 5 are support personnel. In addition, there are 34 auxiliary operators. Twenty-four individuals are in training to take the NRC SRO examination. Sixteen are required positions and 8 are support personnel. Three ROs have passed their NRC license examination and additional ROs are in training. The applicant plans to have as a minimum shift complement during operations: one shift foreman (SRO); two senior control operators (SRO); two reactor operators (RO); and four auxiliary operators. The required minimum shift crew is delineated in the plant Technical Specifications.

Administrative procedures and Technical Specifications have been prepared, which govern shift staffing, use of overtime, and the movement of individuals about the plant in accordance with TMI Action Plan Item I.A.1.3 (NUREG-0737). As documented in Inspection Report No. 50-400/85-16, the appropriate procedures and Technical Specification have been reviewed and found acceptable. The staff considers TMI Action Plan Item I.A.1.3 closed.

The applicant has committed to have shift technical advisors (STAs) assigned to cover all operating shifts. As stated in the FSAR, the qualification requirements for the STAs meet the requirements of TMI Action Plan Item I.A.1.1.

The Plant General Manager has overall responsibility for the initial test program. Under his direction, two basic organizational units, the plant staff and the startup group, jointly conduct different phases of the test program. In addition to these basic organizational units, the Plant General Manager is assisted by two review organizations; the Plant Nuclear Safety Committee (PNSC) and the Joint Test Group (JTG).

The startup organization presently has 34 CP&L and 12 Westinghouse people assigned on site. The startup group is a temporary organization. Eventually, the CP&L startup personnel will be integrated into the permanent plant staff and contract personnel will be brought in as the need arises to augment the plant staff.

### 13.1.2.3 Personnel Qualifications

In FSAR Section 1.8, the applicant identified those plant staff positions for which the qualification requirements are as provided in September Draft ANS 3.1-1979, "Standard for Selection and Training of Personnel for Nuclear Plants," and in Regulatory Guide (RG) 1.8. These positions include the key personnel and the operations staff. The staff has reviewed the résumés of all individuals presently assigned to supervisory positions and above (including reactor operators and above in operations) against the applicable standard, and all meet or exceed the requirements.

Of the 743 people in the Harris Nuclear Project organization, as of April 24, 1986, 184 people had degrees in engineering and 89 had degrees in other fields. Of the 418 people in the Harris Plant Operations Section organization, 69 people had degrees in engineering and 55 had degrees in other fields. The individuals in the line operating organization have the following qualifications: the operations supervisor is an engineer and has been previously licensed; five shift foremen have held an SRO license, and three have previous experience as shift foremen; ten other SRO/RO candidates have been previously licensed. The applicant is aware that the staff requires at least one individual on each operating shift who has substantive previous PWR operating experience, including startup and shutdown of a PWR and under conditions one might expect to encounter during the initial startup and power escalation at Shearon Harris. The applicant has described its shift organization as complying with this requirement by letter dated March 20, 1986. Three shift foremen have had at least one year of operating experience at an operating PWR. Another one of the shift foremen has had 4½ months of operating experience at H. B. Robinson Unit 2. The applicant has provided justification for using this individual to satisfy the NRC requirement for onshift experience. The required experience on another shift will be satisfied by a senior control operator with an SRO license and one year of operating experience as an RO at H. B. Robinson Unit 2. On the basis of the above staffing, the applicant has satisfied the requirement for having at least one individual on each operating shift with substantive previous PWR operating experience for the first six months of operation.

### 13.1.2.4 Conclusions

Following the criteria of SRP Section 13.1.2, the staff concludes that the applicant: (1) has established an acceptable organizational arrangement for plant startup testing and operation; (2) has provided a sufficient number of candidates for licensed positions; (3) has procedures in place concerning shift manning in accordance with TMI Action Plan Item I.A.1.3; (4) has made an acceptable commitment to provide STAs in accordance with the requirements of TMI Action Plan Item I.A.1.1; (5) has established acceptable qualification requirements for plant personnel; and (6) will have at least one individual on each shift with substantive previous PWR operating experience.

The staff concludes that the applicant is technically qualified to operate Shearon Harris within the purview of the regulations and with due regard for public health and safety. The Region II inspection and enforcement program will be applied to ensure that CP&L continues to operate within the regulations.

## 13.2 Training

### 13.2.1 Licensed Operator Training Program

The applicant's April 21, 1986, letter revised its commitment concerning training for mitigating core damage (NUREG-0737 Item II.B.4). Training for mitigating core damage will be provided to STAs and operating personnel from the plant general manager through the operations chain that includes licensed operators. Licensed operators will receive annual retraining in mitigating core damage through the licensed operator requalification program. This should include requalification training in mitigating core damage for licensed and certified instructors as well as STAs.

Managers and technicians in the Instrumentation and Control, Health Physics, and Chemistry Sections will receive training for mitigating core damage commensurate with their responsibilities, but will not receive retraining.

The staff finds that the applicant's commitment regarding mitigating core damage retraining for licensed and nonlicensed personnel meets applicable requirements of NUREG-0737 and Standard Review Plan criteria.

In a letter of September 16, 1986, the applicant revised Section 13.2.1.1.2 of the Shearon Harris FSAR to utilize the plant-referenced simulator for conduct of low-power natural circulation training of licensed personnel prior to full-power operations. If the actual natural circulation tests differ from acceptance criteria, licensed personnel would be notified, the simulator would be modified accordingly, and licensed personnel would be retrained during requalification training. The staff has determined that the simulator training and proposed remedial measures provide an acceptable alternative to meet the commitments for training in natural circulation.

## 13.5 Station Administrative Procedures

### 13.5.1 Administrative Procedures

In Section 13.5.1 of SER Supplement 3, the staff stated that it would report its findings of the two remaining open items on administrative procedures (i.e., Item I.A.1.2, "Shift Supervisor Administrative Duties," and Item I.C.6, "Verification of Correct Performance of Operating Activities"). Subsequently, the NRC Region II staff evaluated the aforementioned procedures and found them acceptable as reported in Office of Inspection and Enforcement (IE) Report 50-400/86-34 dated June 2, 1986. The following paragraphs closing out these items have been excerpted from the above-cited reports:

> Item I.A.1, "Shift Supervisor Administrative Duties"
>
> The inspectors reviewed CP&L's job description for a recently created position identified as "senior clerk" for the operations shift foremen. The operations manager informed the inspectors that CP&L is in the process of hiring enough senior clerks such that each shift will have one. The clerks will be responsible for providing administrative assistance to the operations shift foremen. These responsibilities, in brief, are as follows: in the event of the activation of the site emergency plan, they will make the required telephone contacts to activate the emergency

response team; they will track commitment dates on any assignment, for the assigned shift; and they will prepare a shift status report near the shift change; make call-outs to adequately staff the shift in the event of a vacancy; maintain shift records in a neat, legible fashion; maintain controlled manuals in the control room; prepare memorandums for the shift foreman; maintain an awareness of which plant managers are on call; serve as an access point to the shift foreman; serve as the communications focus between the power plant, the outside and the shift foreman; and control supplies, forms, mail and other administrative documents for the shift. As a result, the inspectors determined that CP&L has provided sufficient controls to significantly reduce the administrative duties of the shift foreman. This item is closed.

Item I.C.6, "Verification of Correct Performance of Operating Activities"

As outlined in Inspection Report 400/85-16, CP&L committed to provide evidence of independent verification. CP&L has provided requirements through the Plant Program Procedure PLP-702, "Independent Verification." The inspectors evaluated the latest revision of this procedure, dated October 17, 1985, which delineates the specific requirements of TMI Action Item I.C.6 and also Regulatory Guide 1.74 and ANSI N18.7. The procedure clearly delineates the program's objectives, responsibilities, definitions, and implementation requirements. This item is closed.

### 13.5.2 Operating and Maintenance Procedures

#### 13.5.2.1 General

Procedures Generation Package

Following the Three Mile Island (TMI) accident, the staff developed the TMI Action Plan (NUREG-0660 and NUREG-0737), which required licensees of operating reactors to reanalyze transients and accidents and upgrade emergency operating procedures (EOPs) (Item I.C.1). The plan also required the NRC staff to develop a long-term plan that integrated and expanded efforts in the writing, reviewing, and monitoring of plant procedures (Item I.C.9). NUREG-0899, "Guidelines for Preparation of Emergency Operating Procedures," represents the staff's long-term program for upgrading EOPs, and describes the use of a Procedures Generation Package (PGP) to prepare EOPs. Submittal of the PGP was made a requirement by Supplement 1 to NUREG-0737, "Requirements for Emergency Response Capability (Generic Letter 82-33)." The generic letter requires each licensee to submit to the NRC a PGP which includes:

(i) Plant-Specific Technical Guidelines

(ii) a Writer's Guide

(iii) a description of the programs to be used for the validation and verification of EOPs

(iv) a description of the training program for the upgraded EOPs.

The staff's review of the applicant's response to Section 7 of Generic Letter 82-33 related to development and implementation of EOPs is given in the material that follows.

Criteria for the review of a PGP are in Standard Review Plan (SRP) Section 13.5.2. Further guidance is contained in NUREG-0899, the reference document for the EOP upgrade portion of Generic Letter 82-33.

The staff determined that the existing PGP is acceptable for the low-power license. The applicant has committed to address a list of items, discussed in the following sections to make them acceptable for the full-power license. These items can be postponed because of the low fission product inventory in the core and the low probability of an accident during the low-power testing period.

By letter dated September 18, 1984, the applicant submitted its PGP for Shearon Harris, Unit 1. That document contained an introduction and the following sections:

- Plant-Specific Technical Guidelines
- Writer's Guide for EOPs
- EOP Verification and Validation Program
- EOP Training Program

On April 28, 1986, the applicant provided additional information. During site visits on July 10 and August 14, 1986, the staff discussed a number of concerns that had arisen during its review. The most significant of these concerns was the added reliance on operator training and knowledge because of the lack of detail in the Harris flowchart-style EOPs. On August 29 and September 19, 1986, the applicant provided additional information on the concerns identified during the site visits.

- <u>Plant-Specific Technical Guidelines (P-STGs)</u>

All licensees and applicants are required to submit P-STGs. These guidelines may be based on generic technical guidelines (prepared by the owner's group), or a plant-specific reanalysis of transients and accidents as described in TMI Action Plan Item I.C.1. In either case, the P-STG should be based on the identification of plant systems and functions, and be supported by an analysis of operator tasks to identify operator information and control needs. If generic technical guidelines are referenced, additional task specification may be needed, depending upon the level of task information provided by the generic technical guidelines, and the nature of deviations from the guidelines. Examples of deviations that should be reviewed and documented are as follows:

- any modification to the mitigative strategy of the generic technical guidelines (e.g., for a Westinghouse plant, initially depressurizing the RCS following a steam generator tube rupture without first having conducted a limited cooldown in accordance with the guidelines to establish a margin to saturation)

- differences in equipment operating criteria (e.g., RCP trip criteria, safety injection (SI) termination criteria)

- differences in equipment operating characteristics (i.e., between the plant-specific equipment and that assumed in the generic analyses, such as SI that can be throttled vs. only on/off)

- identification of methods and equipment used to address the technical areas of the generic guidelines that are specified as "plant-specific"

- plant-specific setpoints or action levels that are calculated or determined in the manner other than specified in the generic technical guidelines

  NOTE: Plant-specific setpoints (e.g., setpoints associated with automatic initiation of ECCS) called for by the generic guidelines need not be included in the P-STG submittal.

- actions that are taken in addition to those specified in the generic guidelines and that affect the mitigative strategy

- differences that affect the equipment's ability to adequately provide the necessary mitigative function

- use of different instruments or control parameters than those specified in the generic technical guidelines or determining instrumentation and control characteristics in a manner different than, or with a different basis than, that specified in the generic technical guidelines

- identification of items not covered by the NRC-approved generic technical guidelines (e.g., plant specific conditions, equipment, operations, or bracketed [ ] information from the generic technical guidelines that relate to systems, functions or methods)

The purpose of the review of the technical guidelines submittal is to determine that the following general objectives are adequately addressed:

- The EOPs will be based on acceptable, validated technical guidelines derived from approved analyses of transients and accidents as described in NUREG-0660, Items I.C.1 and I.C.9, as clarified by NUREG-0737 and Supplement 1 to it, Item I.C.1. The P-STG along with the generic guidelines (if referenced) and supporting documentation provide EOP writers with all the technical information necessary for preparing EOPs which direct operators' actions to mitigate the consequences of transients and accidents without a need to first diagnose an event to maintain the plant in a safe condition (function orientation).

- The PGP describes an adequate method to identify information and control needs to be used as a basis for identifying control room instrumentation and controls necessary to perform the tasks specified in the technical guidelines.

By letters dated September 18, 1984, and April 28, 1986, the applicant provided information on plant-specific emergency response guidelines and referenced the Westinghouse Emergency Response Guidelines (ERGs).

During its July 10 site visit, the staff was able to audit some of the actual EOPs and observe a demonstration of the use of the emergency operating procedures in simulator exercises. In the September 18, 1984, submittal, the applicant identified that the Shearon Harris Nuclear Power Plant design differed from the ERG reference plant in that Shearon Harris is a 3-loop plant versus a referenced 4-loop design. Also, Shearon Harris has a different high-pressure-injection subsystem configuration than the referenced design, although it is functionally the same. The discussion averred that neither difference constituted a safety-significant change. From observation during the visit, the staff concurred with these conclusions.

The September 18, 1984, submittal also described variances between the hardware and instrumentation/control for Shearon Harris and that used in the Westinghouse ERGs. This discussion averred that the variances do not constitute safety-significant deviations. From its audit of the deviation forms and other site visit observations, the staff concluded that the basic mitigating strategies of the Westinghouse ERGs are incorporated in the Shearon Harris EOPs and that the variances identified are not safety-significant changes.

However, from its audit of the Shearon Harris EOPs and the deviation forms, and observations during the site visit demonstrations, the staff noted that immediate trip and safety injection response and response to steam generator tube rupture (SGTR) events are handled using flow-path chart-type procedures. This type of procedure, although not differing in mitigation strategy or objectives from the referenced ERGs, does place a greater reliance on operator-retained knowledge because less detailed information is provided. In addition, the Shearon Harris narrative procedures, which complement the flowcharts, also contain less detail than that called for in comparable ERG steps. In a significant number of steps throughout both types of procedures, the Shearon Harris procedures do not identify the plant-specific means or provide the plant-specific lists as required by the ERGs. Such plant-specific information is necessary as a reference to supplement to the EOPs, as a basis for the plant task analysis program, and as documentation of status in amending the plant-specific guidelines in the future.

During the simulator exercises, the staff noted that often mitigative actions were performed which were not explicitly specified in the EOPs. Also, during the simulator exercises, a certain infacility was apparent regarding the timely identification and diagnosis of SGTR. This may be at least partially attributable to the fact that Shearon Harris status trees do not identify "radioactivity control" as a critical safety function. Because this shortfall is not unique to the Shearon Harris guidelines, and is also evident in the Westinghouse Owners Group (WOG) ERGs, the staff has not treated it as a plant-specific deviation.

For the same radiation-releasing scenarios, it was not clear how the Shearon Harris EOPs interface with the Emergency Action Levels (EALs) of the plant emergency plan. This may be because in none of the simulator exercises was the scenario postulated to progress to a critical state; however, it may be also true that this is related to the same lack of a radiation control critical safety function which is noted above.

From its review, the staff finds that the Shearon Harris EOPs reflect essentially the same objectives and mitigative strategies as the referenced WOG ERGs which were approved for implementation. The EOPs provide appropriate variance to account for plant-specific differences from the reference plant design, but they lack procedural details which the ERGs require. The EOPs do not provide for an easy treatment of SGTR events, at least partly due to the lack of a radiation control safety function, with a related questionable interface with the EALs. On this basis, the staff concludes that the Shearon Harris P-STGs are technically acceptable for interim implementation.

By letters dated August 29 and September 19, 1986, the applicant committed to develop before start of the second fuel cycle a compilation of plant-specific deviations consistent with SRP Section 13.5.2, Section A.3.3.2 recommendations and with associated justifications for each deviation. This expanded document would augment the EOPs, provide basis for the plant task analysis program, and provide reference for future EOP updates. Additionally, the applicant will provide for staff review a list identifying those items from the document for which no plant-specific information will be provided in the EOPs with associated justifications. This list will be provided consistent with deviation document completion. These commitments are acceptable. The radiation control critical safety function and interaction with EALs will be pursued consistent with generic resolution of WOG ERG long-term issues.

- Writer's Guide

Applicants are required to submit a writer's guide that details the specific methods to be used in preparing EOPs which are based on the P-STGs. NUREG-0899 provides objectives and intent for the writer's guide. Because of the variety of available technical writing style guides and other references pertaining to the presentation of information, the specific information found in the writer's guide is expected to vary considerably among plants. For this reason, the staff did not perform a generic review of the human factors aspects of the Westinghouse Owner's Group ERGs. Each applicant has to submit a plant-specific writer's guide for staff review.

The purpose of the evaluation is to determine if acceptable methods are described for accomplishing the following general objectives:

- The writer's guide provides sufficient information for developing EOPs from the P-STG, which are usable, accurate, complete, readable, convenient to use, and acceptable to control room personnel.

- The writer's guide supports upgrading of the procedures and long-term consistency within and between procedures.

During the July 10-11, 1986, site visit, the staff audited a recent revision of the Writer's Guide, audited a sample of EOPs, and observed operators using EOPs during simulator exercises. As a result of that visit, the staff identified many items of concern regarding the Harris Procedures Generation Program. Some of these concerns were programmatic in scope, e.g., adequacy of the training program, apparent inconsistencies between the EOPs and the Writer's Guide. However, most items consisted of very specific details regarding the Writer's Guide. On August 29, 1986, the applicant provided additional information and described various corrective actions. A schedule of implementation was also provided. Staff review of the information indicates that the applicant's proposed corrective actions with the additional commitments, as outlined in its August 29 and September 19, 1986, submittals, are acceptable. The applicant's commitments are summarized below.

(1) The applicant has stated that additional detail would be provided in the EOPs where it "would add clarity to the EOPs...." This information would be added by December 12, 1986. Since this issue also affects training, the applicant has further committed to "perform a review of EOPs and training program to ensure that where plant-specific information is required in EOPs that the information in the EOPs is sufficiently detailed or has been covered adequately by training programs."

If required, additional training and/or EOP revision will be completed before fuel load. Those steps where no additional plant-specific information is given, will be listed and documentation on how operators were training on those tasks will be provided by October 1, 1986.

This commitment is acceptable.

(2) The applicant proposed to correct the inconsistencies between the Writer's Guide and the EOP by revising one or the other or both, as follows:

- Writer's Guide deficiencies will be corrected by October 31, 1986.
- Flowpath procedure deficiencies will be corrected by December 12, 1986.
- "Significant" discrepancies in EPPs and FRPs (narrative procedures) will be corrected by December 12, 1986.
- All other discrepancies between the Writer's Guide and the EOPs will be corrected, and EOPs will be implemented no later than the end of the first refueling outage.

These commitments are acceptable. By letter of September 19, 1986, the applicant committed to support the staff's confirmatory review by providing a complete set of EOPs for staff use, and by providing the results of the EOP review for "significant" discrepancies, and revised EOPs as they become available.

The correction of "significant" discrepancies in procedures may extend up to December 12, 1986, because of the low inventory of fission products in the core below 5% of rated power and the very low likelihood of a severe accident, even if no operator action is taken during this short period. Other less significant discrepancies may be corrected no later than the end of the first refueling outage because of their lesser probability of inducing errors, and because of the low probability of a severe accident during this short time frame.

(3) The applicant proposes to revise the Writer's Guide to correct inconsistent, incorrect, and missing guidance pursuant to most of the staff's recommendations by October 31, 1986.

On the basis of its review, the staff concludes that the Writer's Guide developed for Shearon Harris provides sufficient information for developing EOPs which are usable, accurate, complete, readable, convenient to use, and acceptable to control room personnel, for low-power operation.

To comply fully with the requirements of Supplement 1 to NUREG-0737 regarding the Writer's Guide, the applicant has committed to: (a) revise the Writer's Guide, taking into account specific staff recommendations, by October 31, 1986; (b) apply the revised Writer's Guide to current EOPs and correct significant deficiencies in the EOPs by December 12, 1986; (c) correct all inconsistencies between EOPs and the revised Writer's Guide no later than the end of the first refueling outage.

- Program for Validation/Verification (V/V)

The purpose of evaluating the applicant's V/V program is to determine whether the applicant has provided evidence that the upgraded EOPs are technically correct, are written to accurately reflect the plant-specific Writer's Guide, are usable, correspond to control room/plant equipment, are compatible with minimum number, qualifications, training, and experience of operating staff, and provide a high level of assurance that the procedures will work as a component of the accident mitigation system.

During discussions with the applicant, the staff determined that the applicant did conduct activities that could satisfy the objectives of a verification/validation program. However, the EOPs were not verified to be in compliance with the Writer's Guide. The applicant has committed to documenting its V/V program in its revision to the PGP. This action will be completed by April 15, 1987. The applicant has committed to verify the EOPs are in compliance with the Writer's Guide by the end of the first refueling outage.

The commitment to document the V/V program in the PGP by April 15, 1987, is acceptable because of the low probability of this guidance being needed before that date, i.e., current procedures writers are aware of the necessary V/V processes and are likely to be present for the next revision of EOPs due at first refueling. The commitment to correct all inconsistencies between the EOPs and the Writer's Guide, by the end of first refueling is acceptable for the same reasons stated above. The applicant provided these commitments in letters of August 29 and September 19, 1986.

- Program for Operator Training on EOPs

The purpose of evaluating the applicant's training program on EOPs is to ensure that operators understand the philosophy and the mitigation strategies and technical bases of the EOPs; and that they have a working knowledge of the technical content of the EOPs, and are capable of successfully executing the EOPs under emergency conditions.

The applicant has committed to provide further information by October 1, 1986, and to revise the training section of the PGP by April 15, 1987. Because of the low probability of a severe accident occurring below 5% of rated power, the staff believes that its review and resolution of this issue can extend beyond the date of low-power licensing, but not beyond full-power licensing.

Conclusions

Because the applicant's EOPs are based on the Westinghouse Emergency Response Guidelines that have been approved for interim implementation, and because the EOPs retain the basic mitigation strategies of the Westinghouse ERGs, they contain adequate technical basis. The applicant has committed to add plant-specific information required by the Westinghouse guidelines by October 1, 1986.

The staff concludes that the Writer's Guide provides information for developing EOPs from the P-STGs, which is usable, accurate, complete, readable, convenient to use, and acceptable to control room personnel for low-power operation. The applicant, by letters dated August 29 and September 19, 1986, has committed to revise the Writer's Guide and EOPs. The applicant proposes to implement corrective actions in a phased program; "significant" items will be corrected by December 12, 1986, and all other items will be corrected by the end of the first refueling. This proposal is acceptable.

The applicant has committed to conduct activities which meet the objectives of a V/V program. The applicant has committed to document its V/V process in a revision to the PGP by April 15, 1987. This commitment is acceptable.

The applicant, by letter dated September 19, 1986, has committed to provide information regarding the EOP training program consistent with the training information to be provided for the Writer's Guide. The plant may be operated at low power until this issue is resolved because of the very low likelihood of a severe accident occurring at levels below 5% of rated power. Therefore, the staff finds the training program acceptable for low-power operation.

13.5.2.3 Reanalysis of Transients and Accidents; Development of Emergency Operating Procedures

Item I.C.7, NSSS Vendor Review of Low-Power Operating Procedures

The staff stated in Section 13.5.2.3 of the SER that it would verify the adequacy of the procedures required by NUREG-0737, Item I.C.7, "NSSS Vendor Review of Low-Power Operating Procedures." The following paragraph closing out this item has been excerpted from the Office of Inspection and Enforcement (IE) Report dealing with the verification.

> (Closed) Inspector Follow-up Items 400/85-16-05 "I.C.7.1 NSSS Vendor Review of Low Power Test Procedures" and 400/85-16-31 "I.C.7.2 NSSS Vendor Review of Power Ascension Procedures." The inspectors reviewed the licensee's commitments as described in the FSAR TMI Appendix, page 15; FSAR Section 14.2.3.2; and letters from McDuffie to Denton dated July 1, 1983 and Zimmerman to Denton dated February 18, 1985. Other applicable references included Safety Evaluation Report, Section 13.5.2.3 and Start-up Test Manual, Section 22.5.3.2. The February 1985 letter stated that the review of low power and power ascension procedures related to the NSSS by Westinghouse personnel meet the intent of NUREG-0737 Item I.C.7. NRR has not responded to the licensee's letter. This was discussed with the NRR license project manager, who indicated that the licensee's position is consistent with that of other licensees. The inspectors discussed the

review process and resolution of comments with the cognizant engineer and the NSSS (Westinghouse) vendor representative. Comments are submitted in accordance with AP-06 as described in the start-up test manual. These comments are incorporated as necessary and the revised procedures are reviewed in total by the Westinghouse vendor representative or his designee. The inspectors reviewed select comment sheets. The established process (if continued as described and shown to the inspectors) meets the requirements and intent of I.C.7.1 and I.C.7.2. The other sections of I.C.7 involved vendor review of preoperational and emergency procedures. The preoperation review has been inspected as part of the normal preoperational inspection program. The emergency procedures were developed using Westinghouse technical guidelines and thus require no further vendor review. Therefore I.C.7 is closed in its entirety.

## 13.6 Industrial Security

### 13.6.1 Introduction

The applicant filed with the Nuclear Regulatory Commission the following security plans which have since been amended:

- Shearon Harris Nuclear Power Plant Physical Security Plan
- Shearon Harris Nuclear Power Plant Contingency Plan
- Shearon Harris Nuclear Power Plant Guard Training and Qualification Plan

This SER supplement summarizes how the applicant has provided for meeting the requirements of 10 CFR 73. This section, which supersedes Section 13.6 of the SER in its entirety, is composed of a basic analysis that is available for public review, a protected Appendix, and a protected response force size worksheet which contains safeguards information as described in 10 CFR 73.21.

On the basis of a review of the subject documents and visits to the site, the staff has concluded that the protection provided by the applicant against radiological sabotage at Shearon Harris meets the requirements of 10 CFR 73. Accordingly, the protection provided will ensure that the health and safety of the public will not be endangered.

### 13.6.2 Staff Evaluation

#### 13.6.2.1 Physical Security Organization

To satisfy the requirements of 10 CFR 73.55(b), the applicant has provided a physical security organization that includes a Security Shift Supervisor who is on site at all times with the authority to direct the physical protection activities. To implement the commitments made in the three plans, written security procedures specifying the duties of the security organization members are available for inspection. The training program and critical security tasks and duties for the security organization personnel are defined in the "Shearon Harris Nuclear Power Plant Guard Training and Qualification Plan" which meets the requirements of 10 CFR 73, Appendix B, for the training, equipping, and qualification of the security organization members. The physical security plan and the training program provide commitments that preclude the assignment of any individual to a security-related duty or task before the individual has been trained, equipped, and qualified to perform the assigned duty in accordance with the approved guard training and qualification plan.

13.6.2.2 Physical Barriers

In meeting the requirements of 10 CFR 73.55(c) the applicant has provided a protected area barrier which meets the definition of 10 CFR 73.2(f)(1). An isolation zone of at least 20 feet (to permit observation of activities along the barrier) is provided on both sides of the barrier with the exception of the locations listed in the protected Appendix. The staff has reviewed those locations and has determined that the security measures in place are satisfactory and continue to meet the requirements of 10 CFR 73.55(c).

Illumination of 0.2 foot-candle is maintained for the isolation zones, protected area barrier, and external portions of the protected area. In areas where illumination of 0.2 foot-candle cannot be maintained, special procedures are applied as described in the protected Appendix.

Patrols of the protected area are performed at random intervals to detect the presence of unauthorized persons, vehicles, and materials.

13.6.2.3 Identification of Vital Areas

The protected Appendix contains a discussion of the applicant's vital area program and identifies those areas and items of equipment determined to be vital for protection purposes. Vital equipment is located within vital areas which are located within the protected area and which require passage through at least two barriers, as defined in 10 CFR 73.2(f)(1) and (2), with certain exceptions, to gain access to vital equipment. The staff has reviewed those exceptions and has determined that the barriers are sufficiently substantial to meet the intent of the two-barrier requirement.

Except for the exceptions noted in the protected Appendix, vital area barriers are separated from the protected area barrier. The control room and central alarm station are provided with bullet-resistant walls, doors, ceilings, floors, and windows. On the basis of these findings and the analysis set forth in the protected Appendix, the staff has concluded that the applicant's program for identification and protection of vital equipment satisfies the regulatory intent. However, this program is subject to onsite validation by the staff in the future and to subsequent changes if changes are found to be necessary.

13.6.2.4 Access Requirements

In accordance with 10 CFR 73.55(d) all points of access (personnel and vehicles) to the protected area are controlled. The individual responsible for controlling the final point of access into the protected area is located in a bullet-resistant structure. As part of the access control program, vehicles (except under emergency conditions), personnel, packages, and materials entering the protected area are searched for explosives, firearms, and incendiary devices by electronic search equipment and/or physical search.

Vehicles admitted to the protected area, except applicant-designated vehicles, are controlled by escorts. Applicant-designated vehicles are limited to onsite station functions and remain in the protected area except for operational maintenance, repair, security, and emergency purposes. Personnel authorized to use the vehicles or the escort personnel maintain positive control over these vehicles.

A photo-badge/key-card system, utilizing encoded information, identifies individuals who are authorized unescorted access to protected and vital areas and is used to control access to these areas. Individuals not authorized unescorted access are issued non-photo badges that indicate an escort is required. Access authorizations are limited to those individuals who have a need for access to perform their duties.

Unoccupied vital areas are locked and alarmed. Access to the reactor containment is positively controlled to ensure that only authorized individuals are permitted to enter. In addition, all doors and personnel/equipment hatches into the reactor containment are locked and alarmed. Keys, locks, combinations, and related equipment are changed on an annual basis. In addition, when an individual's access authorization has been terminated because he lacks reliability or trustworthiness, or for poor work performance, the keys, locks, combinations, and related equipment to which that person had access are changed.

13.6.2.5 Detection Aids

In satisfying the requirement of 10 CFR 73.55(e), the applicant has installed intrusion detection systems at the protected area barrier, at entrances to vital areas, and at all emergency exits. Alarms from the intrusion detection system annunciate within the continuously manned central alarm station located in the protected area and within a secondary alarm station also located in the protected area. In addition, the central alarm station is constructed so that the walls, floors, ceilings, doors, and windows are bullet-resistant. The alarm stations are located and designed in such a manner that a single act cannot interdict the capability of calling for assistance or responding to alarms. The central alarm station contains no other functions or duties that would interfere with its alarm response function.

The intrusion detection system transmission lines and associated alarms annunciation hardware are line-supervised and tamper-indicating. Alarm annunciators indicate the type of alarm and its location when activated. An automatic indication of when the alarm system is on standby power is provided in the central alarm station.

13.6.2.6 Communications

As required in 10 CFR 73.55(f), the applicant has provided for the capability of continuous communications between the central and secondary alarm station operators, guards, watchmen, and armed response personnel through the use of a conventional telephone system, and a security radio system. In addition, direct communication with the local law enforcement authorities is maintained through the use of a conventional telephone system and a two-way FM radio link.

All non-portable communication links, except the conventional telephone system, are provided with an uninterruptible emergency power source.

13.6.2.7 Test and Maintenance Requirements

In meeting the requirements of 10 CFR 73.55(g), the applicant has established a program for the testing and maintenance of all intrusion alarms, emergency alarms, communication equipment, physical barriers, and other security-related devices or equipment. Equipment or devices that do not meet the design performance criteria or have failed otherwise to operate will be compensated for by appropriate compensatory measures as defined in the "Shearon Harris Nuclear Power Plant Physical Security Plan" and in onsite procedures. The compensatory measures defined in these plans will ensure that the effectiveness of the security system is not reduced by failures or other contingencies affecting the operation of the security-related equipment or structures.

Intrusion-detection systems are tested for proper performance at the beginning and end of any period that they are used for security. Such testing will be conducted at least once every seven days. Communication systems for onsite communications are tested at the beginning of each security shift. Offsite communications are tested at least once each day.

Audits of the security program are conducted once every 12 months by personnel independent of site security management and supervision. The audits, focusing on the effectiveness of the physical protection provided by the onsite security organization in implementing the approved security program plans, include, but are not limited to: a review of the security procedures and practices, system testing and maintenance programs, and local law enforcement assistance agreements. The applicant's quality assurance and corporate security personnel prepare a report documenting their findings and recommendations and submit it to the applicant for review and necessary action.

13.6.2.8 Response Requirements

In meeting the requirements of 10 CFR 73.55(h), the applicant has provided for armed responders immediately available for response duties on all shifts consistent with the requirements of the regulations (see protected Appendix). Considerations used in support of this number are protected. In addition, liaison with local law enforcement authorities to provide additional response support in the event of security events has been established and documented in the security plan.

The applicant's safeguards contingency plan for dealing with thefts, threats, and radiological sabotage events satisfies the requirements of 10 CFR 73, Appendix C. The plan identifies appropriate security events which could initiate a radiological sabotage event and identifies the applicant's preplanning, response resources, safeguards contingency participants, and coordination activities for each identified event. Through this plan, upon the detection of abnormal presence or activities within the protected or vital areas, response activities using the available resources would be initiated. The response activities and objectives include the neutralization of the existing threat by requiring the response force members to interpose themselves between the adversary and the objective, instructions to use force commensurate with that used by the adversary, and authority to request sufficient assistance from the local law enforcement authorities to maintain control over the situation.

13.6.2.9 Employee Screening Program

In meeting the requirements of 10 CFR 73.55(a) to protect against the design-basis threat as stated in 10 CFR 73.1(a)(1)(ii), the applicant has provided for an employee-screening program. Personnel who successfully pass the employee screening program or its equivalent may be granted unescorted access to protected and vital areas at the Shearon Harris site. All other personnel requiring access to the site are escorted by persons authorized and trained for escort duties and who have successfully passed the employee-screening program. The employee-screening program is based upon accepted industry standards and includes a background investigation, psychological evaluation, and a continuing observation program. The plan also provides for a "grandfather clause" exclusion which allows recognition of a certain period of trustworthy service with the utility or contractor as being equivalent to passing the employee-screening program. The staff has reviewed the applicant's screening program against the accepted industry standards (ANSI NI8.17-1973) and has determined that the program is acceptable.

13.6.2.10 Conclusion

The staff concludes that the applicant's physical security program plans are acceptable. The following proposed license condition is being considered for incorporation into the Facility Operating License when it is issued:

> The licensee shall fully implement and maintain in effect all provisions of the physical security, guard training and qualifications, and safeguards contingency plans previously approved by the Commission and all amendments and revisions to such plans made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: "Shearon Harris Nuclear Power Plant Security Plan" with revisions submitted through September 26, 1986; "Shearon Harris Nuclear Power Plant Guard Training and Qualification Plan" with revisions submitted through October 2, 1985; and "Shearon Harris Nuclear Power Plant Safeguards Contingency Plan" with revisions submitted through October 2, 1985.

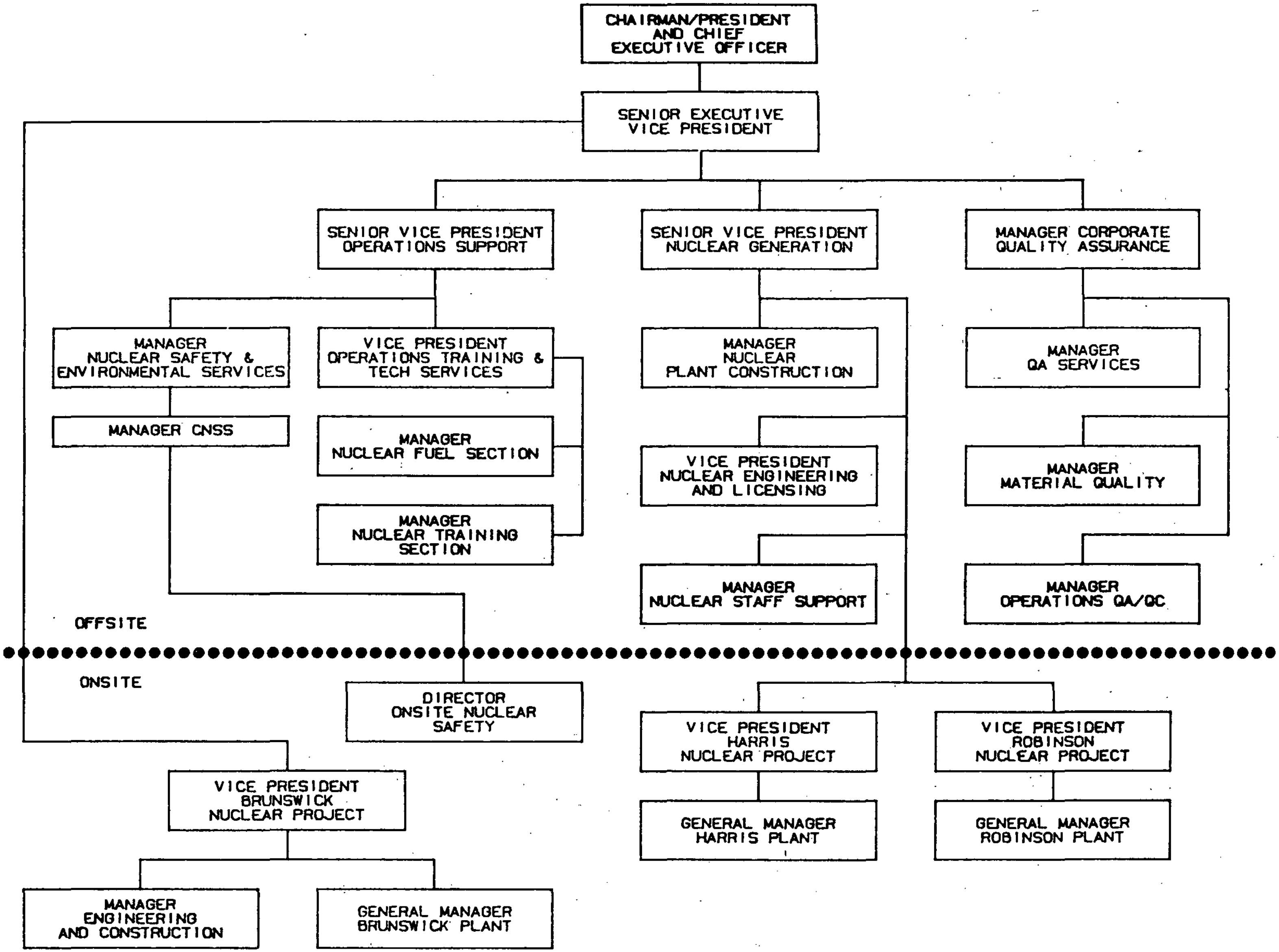


Figure 13.1 CP&L organization and the Operations Support Group

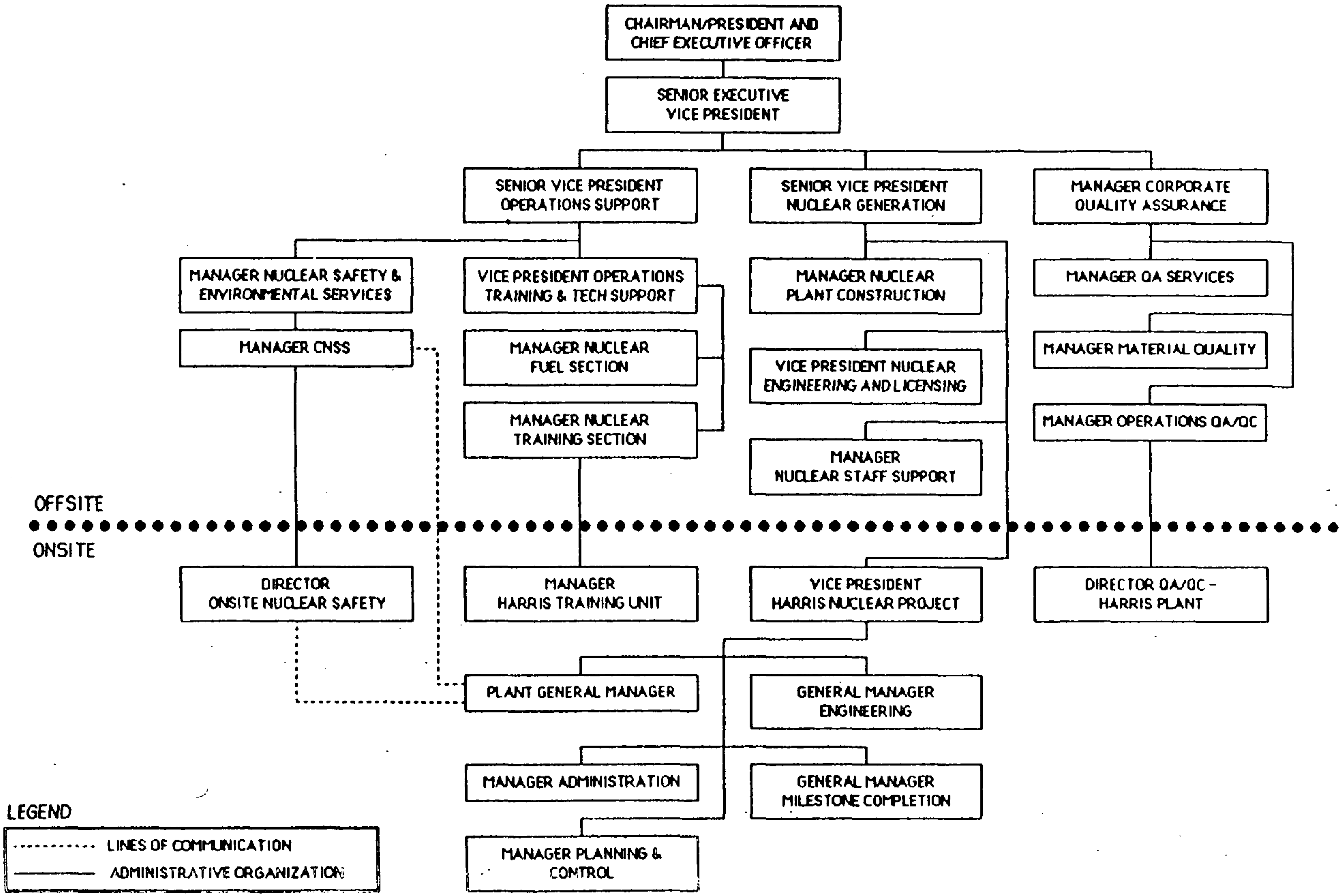


Figure 13.2 The Nuclear Generation Group and the Harris Nuclear Project

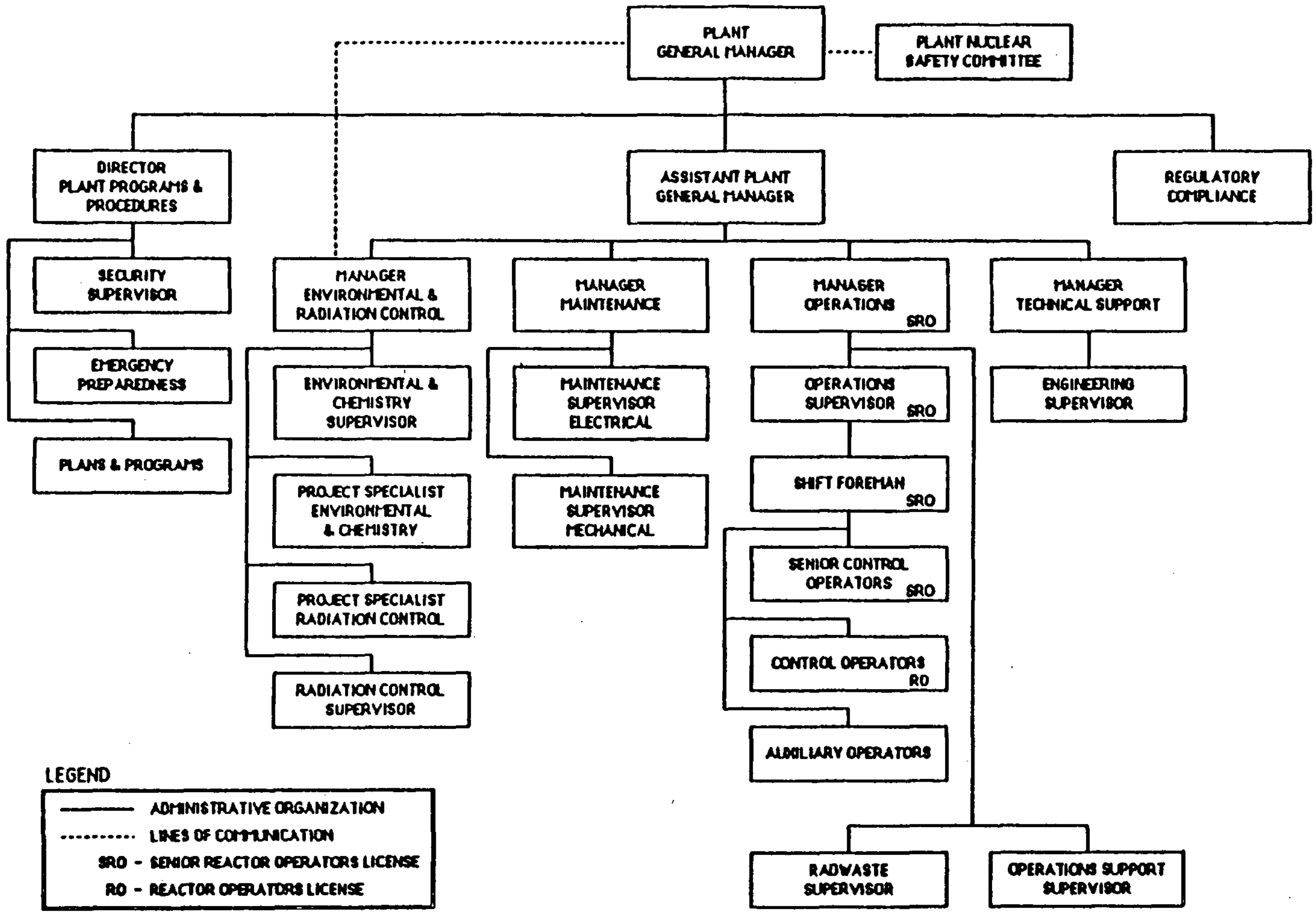


Figure 13.3 Harris Plant Operations Section

# 14 INITIAL TEST PROGRAM

In the SER, the staff concluded that with three exceptions the applicant's initial test program met the applicable regulations and was in accordance with Standard Review Plan (SRP) Section 14.2, and was therefore acceptable. The resolution of those three items is described below. The staff has completed its review of the applicant's description of the initial test program through FSAR Amendment 27 and has reviewed letters dated January 6, May 1, May 2, and August 8, 1986.

The SER required the applicant to either perform tests to verify that the steam generator safety/relief valve capacities do not exceed that assumed in the accident analysis or to provide justification for not performing the testing. The staff's concern was that the actual capacity of the valves might exceed that assumed in the analysis of the inadvertent opening of a relief valve, and therefore, might violate the acceptance criteria for an American Nuclear Society Condition II event. In a letter dated October 14, 1983, the applicant stated that even the double-ended rupture of a main steamline, although a Condition IV event, did not exceed the Condition II event criteria. Because the steamline-break flow rate exceeds the maximum possible flow rate from a relief valve, even if the relief valve capacity is greater than anticipated, the inadvertent opening of a relief valve would not present a safety concern. The staff finds this adequate justification for not performing a capacity test of the relief valves.

A second item in the SER required an FSAR amendment confirming that auxiliary feedwater pump endurance tests would be conducted as proposed in the applicant's July 15, 1982, letter. This modification was provided in FSAR Amendment 27. The staff finds this modification acceptable.

The third item in the SER required confirmatory information regarding natural circulation testing. In FSAR Amendment 27, the applicant provided a natural circulation test description in accordance with NUREG-0737 Item I.G.1. The staff finds this natural circulation test description acceptable. This resolves all confirmatory issues from SER Section 14 (SER Confirmatory Issue 32).

In its May 1, 1986, letter, the applicant took exception to one item in Regulatory Guide (RG) 1.68, "Initial Test Program for Water-Cooled Nuclear Power Plants." Appendix A, Item 1.m.4 of RG 1.68 provides guidance that a full operational test should be performed on cranes used to handle irradiated fuel at 100% of rated load. The applicant stated that the operational test of the manipulator crane would be performed using a dummy fuel assembly and dummy rod cluster control assembly (RCCA) which were equivalent to 98.7% of the weight of an actual fuel assembly with an actual RCCA inserted. Because the static testing of the manipulator crane is being performed at 125% of rated load, this small deviation in the load used for the operational tests is considered inconsequential. Therefore, the applicant's exception to RG 1.68, Appendix A, Item 1.m.4 is acceptable.

By FSAR Amendment 34, the applicant has proposed several changes to the Initial Test Program. The staff finds that these changes will achieve the following results:

(1) Transfer responsibility for conduct of the Startup Power Test Program from the Manager-Startup to the Manager-Technical Support, so that the engineers responsible for plant operation will also be responsible for the startup testing. This will provide valuable experience and should improve plant performance.

(2) Revise acceptance criteria to be consistent with the proposed plant Technical Specifications, the latest Westinghouse design documents, and the applicant's new Setpoint Document. This will provide more accurate and consistent acceptance criteria.

(3) Revise test descriptions to be consistent with the latest revisions of comparable CP&L surveillance and Westinghouse design verification tests. This will provide more reliable and consistent test data.

On the basis of its review of the improvements to the Initial Test Program described by the applicant, the staff finds the applicant's proposed changes acceptable.

The applicant's Initial Test Program as described in the FSAR through Amendment 34 and in related correspondence is acceptable.

This evaluation was performed with assistance of personnel at Battelle Northwest Pacific Laboratories.

# 15 ACCIDENT ANALYSES

## 15.6 Decrease in Reactor Coolant Inventory

### 15.6.3 Steam Generator Tube Rupture (SGTR)

In SER Supplement 2, it was stated that as a result of negotiations between all parties to the Shearon Harris Unit 1 hearings, and as approved by the Atomic Safety and Licensing Board, the license was conditioned as follows:

> Prior to startup, following the first refueling outage, applicants shall submit for NRC review and receive approval of a steam generator tube rupture analysis, including the assumed operator actions, which demonstrates that the consequences of the design basis steam generator tube rupture event for the Shearon Harris Plant are less than the acceptance criteria specified in the Standard Review Plan, NUREG-0800, at § 15.6.3 Subparts II(1) and (2) for calculated doses from radiological releases. In preparing their analysis applicants will not assume that operators will complete corrective actions within the first thirty minutes after a steam generator tube rupture.

The applicant is a member of the Westinghouse Owners Group (WOG) SGTR Subgroup, associated with the resolution of SGTR licensing issues. The WOG analyses include evaluation of the probability and consequences of steam generator overfill, the worst single active failure, and the necessary operator action times. WOG submitted: (1) WCAP-10698, "SGTR Analysis Methodology to Determine Margin to Steam Generator Overfill," in December 1984; (2) Supplement 1 to WCAP-10698, "Evaluation of Offsite Radiation Doses for SGTR Accident," in May 1985; and (3) WCAP-11002, "Evaluation of Steam Generator Overfill Due to SGTR Accident," in February 1986. The staff has completed its review of Supplement 1 to WCAP-10698 and concludes that plant-specific radiological consequence analyses would still be required.

The staff will prepare a generic SER which will include evaluation of the SGTR systems analyses and assumed operator action times in WCAP-10698 and WCAP-11002. The staff will also require plant-specific information including radiological consequence analyses, analyses of steamline static load in the event of overfill, and justification that systems and components credited in the analyses to mitigate accident consequences are safety grade. This information must be submitted at least 6 months before the first refueling shutdown, in order to enable the staff to issue an SER before Cycle 2 startup. The staff further concludes that the low probability of a design-basis accident during the first cycle of operation offers reasonable assurance that Shearon Harris Unit 1 can operate for one cycle until this issue is resolved.

15.6.5 LOCA

15.6.5.2 ECCS Leakage Outside Containment

In FSAR Amendment 26, the applicant corrected Table 6.5.1-3, "Design Data for Reactor Auxiliary Building Emergency Exhaust System." One of the corrections made was to list the charcoal filter bed depth as 2 inches instead of 4 inches. The as-built system has only 2-inch-thick filters. The original design was for 2 inches but the FSAR table incorrectly listed the thickness as 4 inches.

The staff's analysis for a loss-of-coolant accident (LOCA) depends on this charcoal filter to remove a fraction of airborne iodine activity outside the containment. The SER gave credit for 99% iodine removal which is appropriate for a 4-inch-thick charcoal filter.

This removal credit is no longer valid. For a 2-inch charcoal bed filter with appropriate humidity control, the iodine removal efficiency that should apply is 95%. Therefore, the site boundary LOCA thyroid doses will increase from those valves listed in Table 15.1 of the SER.

The corrected thyroid doses are as follows:

- Exclusion-area thyroid total LOCA dose increases from 80 rems to 103 rems.
- Low-population-zone total thyroid LOCA dose increases from 90 rems to 155 rems.

These doses are still within the limits set forth in 10 CFR 100 for the LOCA and, accordingly, are considered acceptable.

15.8 Anticipated Transients Without Scram

Generic Letter 83-28

On July 8, 1983, the Nuclear Regulatory Commission (NRC) issued Generic Letter (GL) 83-28. This letter addressed intermediate-term actions to be taken by licensees and applicants aimed at assuring that a comprehensive program of preventive maintenance and surveillance testing is implemented for the reactor trip breakers (RTBs) in pressurized-water reactors. In particular, Item 4.1 of the letter required licensees and applicants to verify that all vendor-recommended reactor trip breaker modifications have been implemented. Item 4.2 required them to submit a description of their preventive maintenance and surveillance program to ensure reliable reactor trip breaker operation.

The applicant submitted responses to the generic letter on November 7, 1983, and May 6, 1986. The adequacy of the applicant's responses and of its preventive maintenance and surveillance programs for RTBs follow.

Action Item 2.1 (Part 1)

The following is an evaluation of the response submitted by the applicant concerning Item 2.1 (Part 1) of Generic Letter 83-28. The documents reviewed as part of this evaluation are:

- 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.
- Letter, A. B. Cutter, CP&L, to D. G. Eisenhut, NRC, November 7, 1983.
- Letter, S. R. Zimmerman, CP&L, to H. R. Denton, NRC, May 31, 1985.

Item 2.1 (Part 1) requires the licensee to confirm that all reactor trip system components are identified, classified, and treated as safety-related as indicated in the following statement:

> Licensees and applicants shall confirm that all components whose functioning is required to trip the reactor are identified as safety-related on documents, procedures, and information handling systems used in the plant to control safety-related activities, including maintenance, work orders, and parts replacement.

The applicant responded to the requirements of Item 2.1 (Part 1) with submittals dated November 7, 1983 and May 31, 1985. The applicant stated that a Q-list identifying safety-related components had been developed and plant procedures had been implemented to ensure that components whose function is required to trip the reactor were identified as safety-related on documents used to control safety-related activities. A copy of this evaluation is attached as Appendix L.

On the basis of its review of these responses, the staff finds the applicant's statements confirm that a program exists for identifying, classifying, and treating components that are required for performance of the reactor trip function as safety-related. This program meets the requirements of Item 2.1 (Part 1) of Generic Letter 83-28 and is, therefore, acceptable.

Action Item 4.1

All vendor-recommended reactor trip breaker modifications shall be reviewed to verify that either: each modification has, in fact, been implemented, or a written evaluation of the technical reasons for not implementing a modification exists.

The applicant committed to incorporate vendor-recommended modifications on the DS-416 RTBs. The staff finds the applicant's position on Item 4.1 to be acceptable.

Action Item 4.2.1

A planned program of periodic maintenance, including lubrication, housekeeping, and other items recommended by the equipment supplier should be submitted.

The primary source for periodic maintenance program criteria for Item 4.2.1 is Westinghouse Maintenance Program Manual for DS-416 Reactor Trip Circuit Breakers, Rev. 0. This document was prepared for the Westinghouse Owners Group and is the breaker manufacturer's recommended maintenance program for the DS-416 breaker. It provides specific direction with regard to schedule, inspection and testing, cleaning, lubrication, corrective maintenance, and recordkeeping. The document was reviewed to identify those items that contribute to RTB reliability consistent with the generic letter. Those items identified for maintenance at 6-month intervals (or when 500 breaker operations have been counted, whichever comes first) that should be included in the applicant's RTB maintenance program are:

- general inspection to include checking of breaker's cleanliness, all bolts and nuts, pole bases, arc chutes, insulating link, wiring, and auxiliary switches
- retaining rings inspection, including those on the undervoltage trip attachment (UVTA)
- arcing and main contacts inspection as specified by the Westinghouse Maintenance Manual
- UVTA check as specified by the Westinghouse Maintenance Manual, including replacement of UVTA if dropout voltage is greater than 60% or less than 30% of rated UVTA coil voltage
- shunt trip attachment check as specified by the Westinghouse Maintenance Manual
- lubrication as specified by the Westinghouse Maintenance Manual
- functional check of the breaker's operation before returning it to service

The applicant's RTB periodic maintenance should also include, on a refueling interval basis:

- precleaning insulation resistance measurement and recording
- RTB dusting and cleaning
- postcleaning insulation resistance measurement and recording, as specified by the Westinghouse Maintenance Manual
- inspection of main and secondary disconnecting contacts, bolt tightness, secondary wiring, mechanical parts, cell switches, instruments, relays, and other panel-mounted devices
- UVTA trip force and breaker load check as specified by the Westinghouse Maintenance Manual
- measurement and recording of RTB response time for the undervoltage trip
- functional test of the breaker before returning it to service, as specified by the Westinghouse Maintenance Manual

The applicant states that its preventive maintenance program is in accordance with the recommendations of the Westinghouse Maintenance Manual for the DS-416 RTB, will include the items listed above, and that the maintenance will be performed according to the schedule discussed in the Westinghouse Maintenance Manual, with the exception that UVTAs will be replaced under a maintenance work request. The staff finds that the applicant's maintenance interval is acceptable. This acceptance is based on the Westinghouse recommendation that maintenance on RTBs located in mild environments should be performed annually. The vendor recommendation that RTBs located in harsh environments or experiencing severe load conditions be maintained more frequently is not applicable to these RTBs because of their location in a mild environment and reduced service duty at Shearon Harris (less than 200 RTB cycles per refueling interval). The staff finds the applicant's position on Item 4.2.1 acceptable.

Action Item 4.2.2

Trending of parameters affecting operation and measured during testing to forecast degradation of operation should be included in the applicant's preventive maintenance and surveillance program.

The variables measured during the maintenance program described above which are applicable for trending are undervoltage trip attachment dropout voltage, trip force, response time for undervoltage trip, and breaker insulation resistance. The staff position is that the above parameters are acceptable and recommended trending parameters to forecast breaker operation degradation or failure. If subsequent experience indicates that any of these parameters is not useful as a tool to anticipate failures or degradation, the licensee or applicant may, with justification and NRC approval, elect to remove that parameter from those to be tracked.

The applicant has committed to an RTB parametric trend monitoring program which will include all of the parameters listed above. The staff finds the applicant's position on Item 4.2.2 acceptable.

Conclusions

The staff finds the applicant's position on Items 4.1, 4.2.1, and 4.2.2 of Generic Letter 83-28 to be acceptable.

Generic Letters 85-09 and 83-28

Generic Letter 85-09 and Item 4.3 of Generic Letter 83-28 specify Technical Specification changes applicable to the reactor trip system instrumentation and surveillance. These letters concluded that such Technical Specification changes should be proposed by licensees and applicants to explicitly require independent testing of the undervoltage and shunt trip attachments of the reactor trip breakers during power operation, testing of bypass breakers before use, and independent testing of the control room manual switch contacts and wiring during each refueling outage. These changes have now been incorporated in the Westinghouse Standard Technical Specifications.

The applicant has adopted the Westinghouse Standard Technical Specifications as part of its license. Generic Letter 85-09 pertains to the following Technical Specifications in the Shearon Harris license.

- Table 3.3-1, Functional Unit 1 (Manual Reactor Trip), Functional Unit 20 (Reactor Trip Breakers), Functional Unit 21 (Automatic Trip and Interlock Logic), Functional Unit 22 (Reactor Trip Bypass Breakers)

* Table 4.3-1, Functional Unit 1 (Manual Reactor Trip), Functional Unit 20 (Reactor Trip Breakers), Functional Unit 21 (Automatic Trip and Interlock Logic), Functional Unit 22 (Reactor Trip Bypass Breakers)

The staff has reviewed the final draft of the Shearon Harris Unit 1 Technical Specifications for the above functional units, including the action statements and table notations, and finds they are consistent with those of Generic Letter 85-09. Therefore, the staff finds that they are acceptable.

## 15.9 TMI Action Plan Requirements

### 15.9.9 II.K.3.5, Automatic Trip of RCPs During LOCA

Generic Letter 85-12 required owners of Westinghouse nuclear steam generating systems to evaluate their plants with respect to RCP trip. The objective was to demonstrate that their proposed RCP trip setpoints assure pump trip for small-break LOCAs and, in addition, to provide reasonable assurance that RCPs are not tripped unnecessarily during non-LOCA events. A number of plant-specific items were identified which were to be considered by applicants and licensees, including the selected RCP trip parameter, instrumentation quality and redundancy, instrumentation uncertainty, possible adverse environments, calculational uncertainty, potential RCP and RCP-associated problems, operator training, and operating procedures.

The applicant has addressed most, but not all, of the criteria identified in Generic Letter 85-12. The staff has evaluated the information provided by the applicant pertinent to this issue. The staff finds the applicant's response to Generic Letter 85-12 to be potentially deficient with respect to differentiation between non-LOCA and LOCA conditions. The likelihood and impact of this condition are judged to be sufficiently small that resolution of the issue is not required before a low-power license is issued, but will require further discussion before a decision can be made to issue a full-power license.

### 15.9.13 II.K.3.30, Revised Small-Break LOCA Methods To Show Compliance With 10 CFR 50, Appendix K

The staff approved the new Westinghouse small-break LOCA model NOTRUMP on May 21, 1985, and referenced Westinghouse documents WCAP-10054 and WCAP-10079. The staff found the model to be in compliance with Appendix K to 10 CFR 50. Therefore, the staff concludes that the use of NOTRUMP for small-break LOCA analysis is acceptable for Westinghouse nuclear steam supply system (NSSS) designs and meets the requirements of TMI Action Plan Item II.K.3.30.

### 15.9.14 II.K.3.31, Plant-Specific Calculations To Show Compliance With 10 CFR 50.46

In response to the above requirement, the applicant has submitted a plant-specific analysis which is in compliance with 10 CFR 50.46 (refer to SER Section 6.3.5.2). Therefore, the staff concludes that the applicant has met the requirements of TMI Action Plan Item II.K.3.31.

# 16 TECHNICAL SPECIFICATIONS

Item 1 of Table 16.1 has been deleted and is discussed in Sections 2.4.2.2 and 2.4.14 of this supplement. The requirements of item 2 have been modified as discussed in Section 2.4.11.2 of this supplement. Item 3 was erroneously identified as a Technical Specification requirement. The applicant has completed the 2-year seismic monitoring program of the reservoir as required by the staff in Section 2.5.2.6 of the SER. Items 26 and 30 have been deleted and are discussed in Sections 10.4.9 and 4.3, respectively. Table 16.1 has been revised to show where the remaining items have been incorporated into the cited sections of the Technical Specifications.

Table 16.1 Issues resolved by inclusion in Shearon Harris Technical Specifications

| Issue | | Status | Applicable SER/Tech. Spec. sections(s)* |
|---|---|---|---|
| (1) | Watertight and airtight doors normally closed | Deleted (SSER 4) | 2.4.2.2, 2.4.14 |
| (2) | Defining procedures to ensure that sediment deposition does not adversely affect the emergency water supply | Modified (SSER 4) | 2.4.11 |
| (3) | Monitoring of reservoir level for 2 years | Deleted (SSER 4, Section 16) | 2.5.2.6 |
| (4) | Compliance with provisions of RG 1.125 | | 2.5.6.7, 2.2.6.9 (6.8.4.f) |
| (5) | Regulating rod insertion controlled by power-dependent insertion limit | | 4.3 (3.1.3.6) |
| (6) | Wide Δ I band | | 4.3.2 (3.2) |
| (7) | Reactor coolant system flow monitored every 24 hours | | 4.4.3.3.1 (4.2.3.3) |
| (8) | Revision of flow uncertainties | | 4.4.3.3.1 (3.2.3) |
| (9) | Rod bow provisions | | 4.4.3.3.3 (B.3/4.2) |
| (10) | Loose parts monitoring system | | 4.4.4 (3.3.3.9) |
| (11) | Provisions prohibiting N-1 loop operation | | 4.4.6.4 (3.4.1.1) |
| (12) | Leakage through valves serving as pressure isolation boundaries (inventory balance) | | 5.2.5 (3.4.6.2) |
| (13) | Requirements from modifications to D4 steam generation | | 5.4.2.2.2 (3/4.4.5) |
| (14) | Periodic leak integrity tests | | 6.2.4 (3.6.1.2) |
| (15) | Demonstrate need for continuous operation of the normal containment purge system | | 6.2.4 (3.6.1.7) |
| (16) | Containment isolation setpoint pressure | | 6.2.4 (3.2.2) |
| (17) | Limit on control room pressure flow to less than or equal to 315 cfm at pressures greater than 1/8 in. water gauge | | 6.4 (3.7.6) |
| (18) | Trip setpoint methodology | | 7.2.2.2 (2.2.1, 3.3.1, 3.3.2) |
| (19) | Response time testing | | 7.2.2.3 (3.3.1, 3.3.2) |
| (20) | Testing of spare CCW pump breaker and surge tank level instrumentation | | 7.3.3.9 (3/4.7.3) |
| (21) | Testing of spare charging pump breaker | | 7.3.3.10 (3.4.1.2) |
| (22) | Periodic testing of safety-related portion of the service water system and CCW system | | 9.2.1, 9.2.2 (3.7.3) |

Table 16.1 (Continued)

| Issue | | Status | Applicable SER/Tech. Spec. sections(s)* |
|---|---|---|---|
| (23) | Periodic testing of the ESCWS | | 9.2.7 (3.7.13) |
| (24) | Post-maintenance test on emergency diesel generator in accordance with the surveillance requirements of the Standard Technical Specifications | | 9.5.4.1 (3.8.1) |
| (25) | Outage time with two and three auxiliary feed-water pumps inoperable | | 10.4.9 (3.7.1.2) |
| (26) | Flow test after cold shutdown to verify normal AFW system flow path | Deleted (SSER 4) | 10.4.9 |
| (27) | Process and effluent monitoring system | | 11.5.2 (3.3.3.1, 3/4.11) |
| (28) | Minimum containment pressure | | 6.2.1.5 (3.6.1.4) |
| (29) | Pressure isolation valve leak rate | | 3.9.6 (3.4.6.2) |
| (30) | Excore detectors | Deleted (SSER 4) | 4.3 |

*Technical Specification sections are in parentheses.

# 17 QUALITY ASSURANCE

## 17.2 Organization

As a result of the staff's review of FSAR Amendment 26, the staff has determined that organizational changes have been made necessitating a revision of SER Section 17.2. The following supersedes the material reported in the Shearon Harris SER dated November 1983.

The structure of the organization responsible for the operation of Shearon Harris Unit 1 and for the establishment and execution of the operations phase quality assurance (QA) program is shown in Figure 17.1

The Chairman/President is responsible for setting QA policies, goals, and objectives. The Senior Executive Vice President - Power Supply and Engineering and Construction, reporting to the Chairman/President, has overall responsibility for the engineering, operations, and QA activities at Shearon Harris Power Plant. He executes his responsibilities through the Senior Vice President - Nuclear Generation, Senior Vice President - Operations Support, and the Manager - Corporate Quality Assurance.

The Senior Vice President - Nuclear Generation is responsible for managing the design, construction, operation, and maintenance of the Shearon Harris Nuclear Power Plant. He has assigned the responsibility for managing the design, construction, operation, and maintenance of Shearon Harris plant to the Vice President - Harris Nuclear Project. He has assigned the responsibility for licensing and engineering support of the applicant's nuclear generating facilities to the Vice President - Nuclear Engineering and Licensing Department. He has assigned the responsibility for procurement and contracting support for all nuclear generating facilities to the Manager - Nuclear Plant Construction Section. He has assigned the responsibility for coordinating the implementation and maintenance of programs to the Manager - Nuclear Staff Support Section.

The General Manager - Harris Plant Operations Section who reports to the Vice President - Harris Nuclear Project is responsible for all operational phases of plant management, including operation, maintenance, and technical support. He manages and controls the organization through personal contact with the Assistant General Manager and seven unit heads (not shown on Figure 17.1) and through written reports, meetings, conferences, and inplant inspections. He is responsible for adherence to all requirements of the operating license, Technical Specifications, Corporate Quality Assurance Program, and Corporate Health Physics and Nuclear Safety policies, the establishment and approval of qualification requirements for all Harris Plant Operations staff positions; the personal review of the qualifications of specific personnel for managerial and supervisory positions in the Harris Plant Operations Section; and the review of and concurrence in the plant radiation protection, industrial security, quality assurance, fire protection, training, operations, and maintenance programs.

The Senior Vice President - Operations Support is responsible for the management of the materials and fuel needs at Shearon Harris. He provides senior management, up to and including the Chairman/President and the Board of Directors, a continuing assessment of current nuclear safety programs.

The Manager - Corporate Quality Assurance is assigned authority and responsibility for the CP&L Corporate Quality Assurance Program. He reports directly to the Senior Executive Vice President - Power Supply and Engineering and Construction. He is independent from cost and schedule responsibilities and has no other duties or responsibilities that would prevent his full attention to QA matters.

The Corporate Quality Assurance Manager has access to corporate management up to and including the Chairman/President to resolve any QA-related concerns if the concerns cannot be resolved satisfactorily at a lower management level. He has delegated the responsibility for implementation of the Corporate QA Program to the Manager - Operations Quality Assurance/Quality Control Section, the Manager - Quality Assurance/Quality Control Harris Plant and the Manager - QA Services Section (see Figure 17.2).

The quality assurance/quality control (QA/QC) organizations are in the review and concurrence cycle for procedures that address QA requirements such as administrative procedures involving QA program requirements, maintenance and modification procedures, preoperational test procedures, and surveillance test procedures.

QA/QC personnel participate in plant meetings and review schedules to keep abreast of plant activities and ensure that sufficient qualified QA/QC manpower and procedures are made available to provide the necessary QA/QC coverage for the scheduled activities.

Responsible plant and QA/QC personnel are required to be knowledgeable of the FSAR commitments, with particular emphasis given to Technical Specifications, regulatory guides, and codes and standards. Procedural controls will be developed that detail accountability and define the system for ensuring that FSAR commitments and changes/additions to those commitments are correctly translated into implementation procedures and instructions. Proper implementation of this procedure and FSAR commitments will be subject to surveillance and audit by QA personnel. As an additional check, QA personnel will develop a matrix of Technical Specification commitments versus implementing procedures to provide a level of assurance that Technical Specification commitments are addressed in implementing procedures. Procedural compliance will be verified through QA surveillances and audits.

The Manager - Operations Quality Assurance/Quality Control has direct management responsibility for the QA/QC activities related to the startup and operation of Shearon Harris. He has delegated the responsibility for implementation of the Corporate QA program to the Director - Harris Operations QA/QC.

The Director - Harris Operations QA/QC is responsible for conducting the onsite QA/QC activities during startup and operation of Shearon Harris in accordance with the Corporate QA program and QA/QC procedures. The Director - Harris Operations QA/QC has delegated the authority necessary for implementation of his portion of the Corporate QA Program to the Operations QA Supervisor, Operations QC

Supervisor, and the Operations Principal QA Engineer. The Director - Harris Operations QA/QC receives support from the Manager - QA/QC Harris Plant on an as-needed basis. The responsibilities of the Manager - QA/QC Harris Plant include reviewing plant modification documents and selected plant procedures and instructions to ensure that quality requirements are adequately prescribed; ensuring holdpoints have been inserted in work control documents and conducting inspections of maintenance and modification activities; reviewing purchase requisitions and ensuring that QA/QC requirements are specified; coordinating/ conducting surveillance of ongoing plant activities; and stopping maintenance and modification work that does not meet requirements.

The Manager - QA Services Section is responsible for providing the offsite QA services support in areas of engineering quality assurance, vendor surveillance, and training. He is also responsible for conducting an independent corporate audit program for all CP&L nuclear plants. He has delegated the authority necessary to fulfill his responsibilities to the Principal QA Engineer, the Principal Specialist - Vendor Surveillance, the Principal QA Specialist - Training and Administration, and the Principal QA Specialist - Performance Evaluation.

The Principal QA Engineer is located at the corporate office and is responsible for reviewing contracts for inclusion of applicable QA/QC requirements; reviewing design specification and site-generated specifications and their revisions for QA requirements and for compliance with specific QA/QC and code requirements when the procedures are designated for use with code items at the construction site; and for ensuring timely resolution of identified concerns and nonconformances.

The Principal Specialist - Vendor Surveillance, located at the corporate office, is responsible for conducting inspections and item acceptance activities at supplier facilities for procurement and ensuring timely resolution of identified concerns and nonconformances; evaluating suppliers' corrective actions to prevent recurrence of nonconformances identified during shop inspections; and conducting audits of suppliers' quality-related activities.

The Principal QA Specialist - Performance Evaluation is located at the corporate office and is responsible for conducting an independent corporate audit program. Personnel in this unit have no responsibility for QA functions other than auditing. Reports of all audit results are distributed to the Chairman/President, Executive Vice President - Power Supply and Engineering and Construction, and to the management of the function audited.

The Project QA Specialist - Training and Administration is also located at the corporate office and is responsible for maintaining the QA/QC program and procedures for corporate and/or field use, including document control and coordination of preparation of revisions; maintaining the Corporate QA Program, including document control and coordination of preparation of revisions, and assisting other corporate QA units in developing, implementing, and maintaining a training program to qualify an upgrade QA/QC personnel.

The staff has not altered its previous conclusion that the applicant's description of the QA program is in compliance with the applicable NRC regulations.

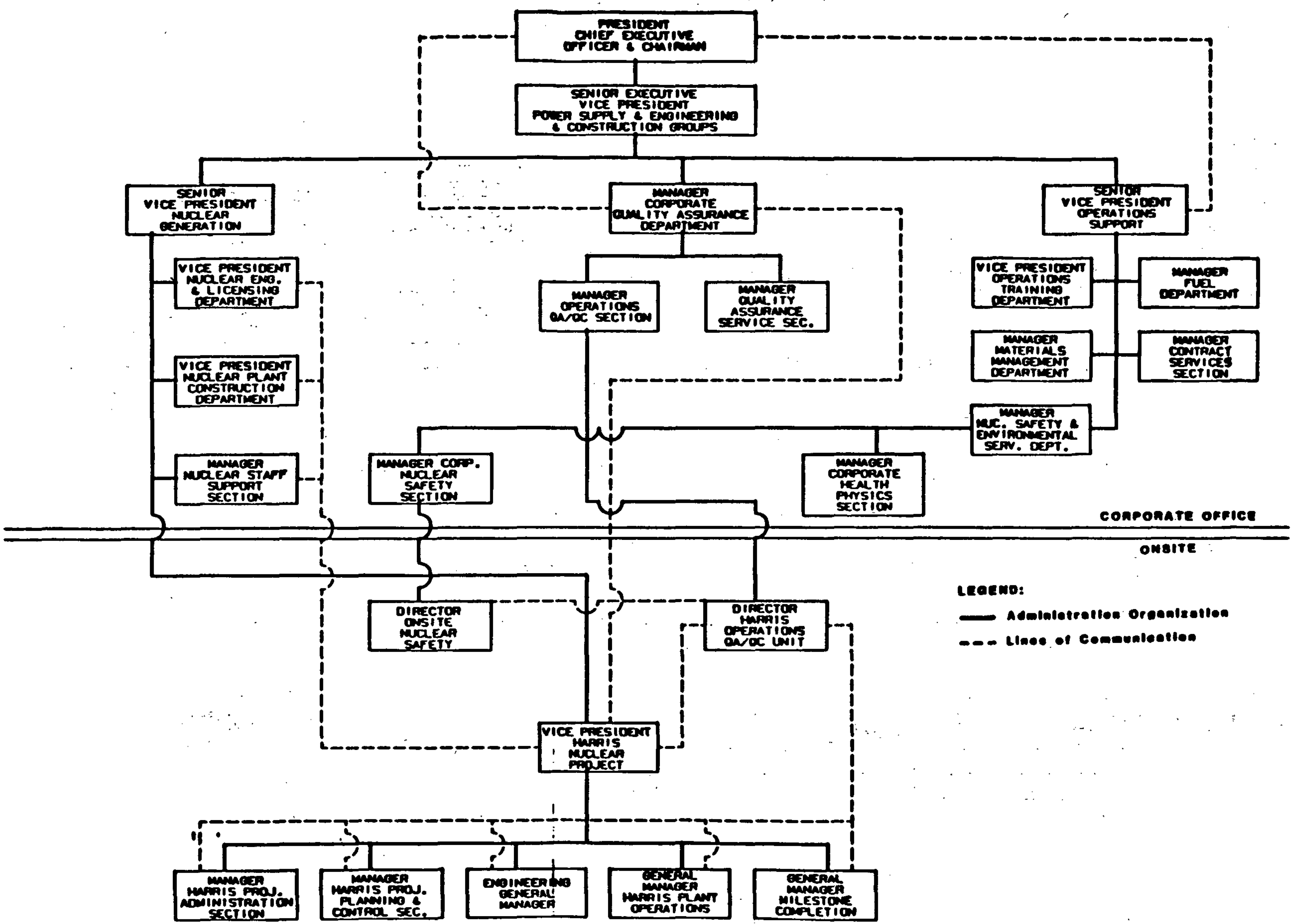


Figure 17.1 CP&L corporate organization

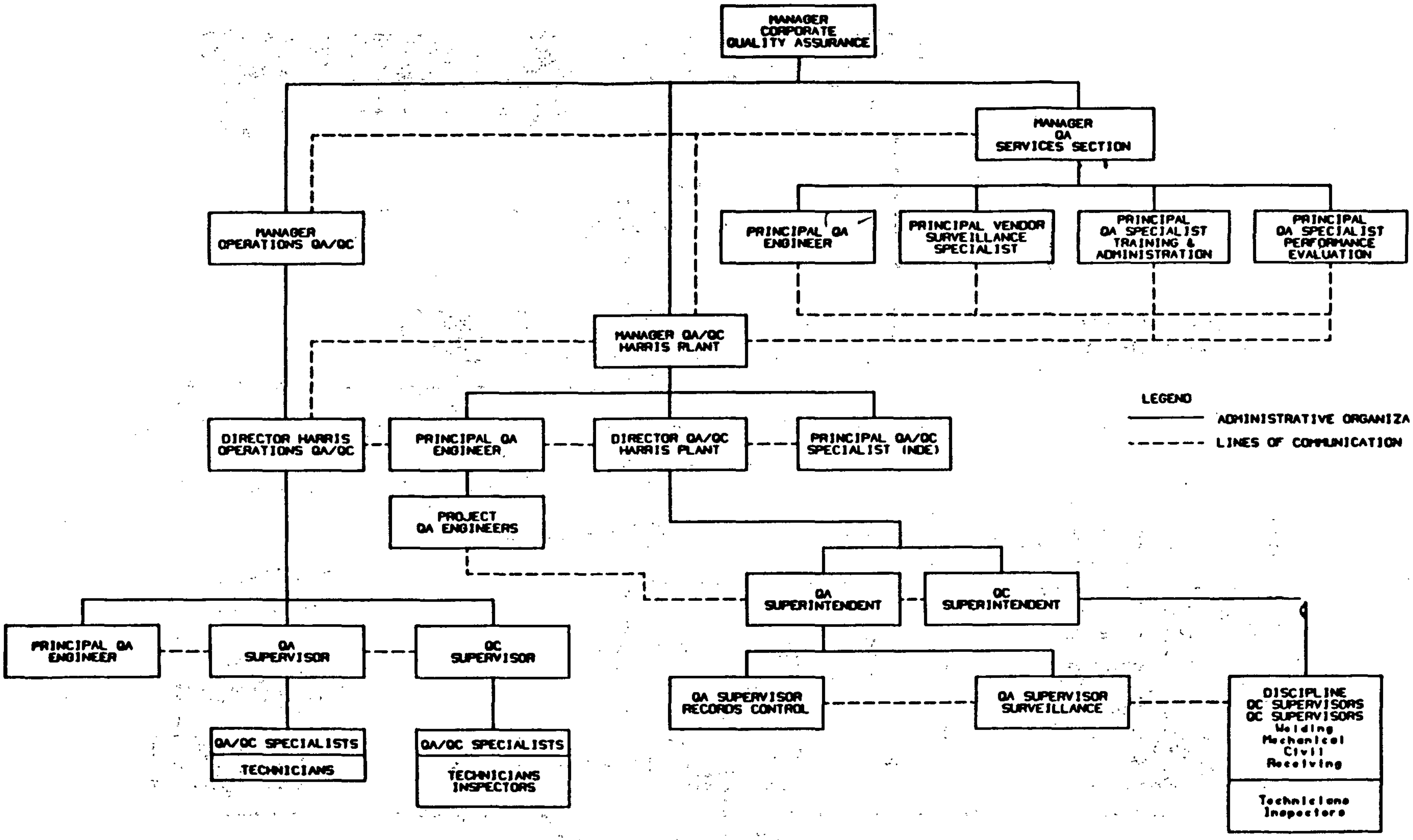


Figure 17.2 CP&L QA organization

## 18 HUMAN FACTORS ENGINEERING

Item I.D.1, "Control Room Design Reviews," of Task I.D, "Control Room Design," of the Nuclear Regulatory Commission (NRC) Action Plan (NUREG-0660) developed as a result of the Three Mile Island Unit 2 accident states that licensees and applicants for operating licenses will be required to perform a detailed control room design review (DCRDR) to identify and correct design discrepancies. The objective, as stated in NUREG-0660, is to enhance the ability of nuclear power plant control room operators to prevent accidents or to cope with accidents if they occur by improving the information provided to them. Supplement 1 to NUREG-0737 confirmed and clarified the DCRDR requirement in NUREG-0660. As a result of this clarification, each applicant or licensee is required to conduct its DCRDR on a schedule negotiated with NRC.

### 18.1* Detailed Control Room Design Review

The applicant submitted (1) a preliminary planning report entitled "Human Factors Design Evaluation Report for the Shearon Harris Unit 1 Control Room," dated January 23, 1981, and revised September 16, 1981, and April 14, 1983; (2) supplemental information dated May 13, 1983; and (3) errata sheets. These were submitted to the NRC with the applicant's letter of transmittal on June 1, 1983. A human factors engineering in-progress audit of the Shearon Harris Nuclear Power Plant control room design review was performed at the site on August 15 through August 18, 1983. The audit was carried out by the staff assisted by consultants from Lawrence Livermore National Laboratory (LLNL). A report, "Comments on the Design Evaluation Report Program Plan (Program Plan)," and an in-progress audit report were issued on April 4, 1984. The applicant submitted the "Control Room Design Summary Report for Shearon Harris Nuclear Power Plant, Unit 1," dated March 1985, to the NRC on April 9, 1985. The staff issued comments on this submittal on August 14, 1985. By its letter of September 13, 1985, the applicant submitted its "DCRDR Final Summary Report." A meeting between representatives of the applicant, the NRC, and LLNL was held in Bethesda, Maryland, on December 20, 1985, to discuss and clarify the concerns of the NRC and the draft Technical Evaluation Report prepared by LLNL. An onsite visit to the control room and a meeting between NRC staff and the applicant and its consultants to review and discuss NRC and LLNL concerns took place on March 18-19, 1986. The applicant submitted to the NRC revisions (replacement sections) to the Final Summary Report (Revision 1) dated April 28, 1986, additional information dated May 30, 1986, and Revision 2 to the Shearon Harris CRDR Final Summary Report dated June 30, 1986.

In the TER, LLNL concluded that the applicant has conducted a DCRDR for Shearon Harris that meets five elements of Supplement 1 to NUREG-0737 (see Appendix M, this supplement). In order to satisfy the remaining elements, the applicant should:

(1) Submit the results of the remaining items of the preliminary control room survey.

---

*Previously titled "<u>General</u>."

(2) Advise of the completion of corrective actions for the AEP-1 panel, so the NRC staff can visit the site to review this panel and the corrective actions.

(3) Submit for NRC review the process for assessing cumulative and interactive effects of HEDs.

(4) Describe in sufficient detail the coordination of the control room activities to allow the staff to reach a conclusion about the adequacy of this effort as discussed in the TER.

The applicant advised the staff that corrective actions for the AEP-1 panel have been completed. On August 19, 1986, the staff visited the control room to review the AEP-1 panel; at that time there was also a meeting between the NRC staff and representatives of CP&L at the site to discuss and clarify the open items. The applicant documented the clarification that had been discussed at the site visit and meeting by its letter dated August 29, 1986.

The staff's conclusions with regard to each of the elements of the DCRDR required by Supplement 1 to NUREG-0737 are summarized below.

### 18.1.1 Multidisciplinary Review Team

On the basis of the Summary Report, the in-progress audit, and discussion during the audit, the staff concludes that the applicant has established a qualified multidisciplinary review team which meets the requirements of Supplement 1 to NUREG-0737.

### 18.1.2 System Function and Task Analysis

The use of a plant-specific version of the System Review and Task Analysis from the Westinghouse Owners Group (WOG) as the basis of the Shearon Harris Unit 1 system function and task analysis (SFTA) process is acceptable as discussed in NUREG-0800, Section 18.1, Appendix A. The methodology and process as described in the Summary Report and in discussions with the applicant are acceptable and meet the requirements of Supplement 1 to NUREG-0737. However, in reviewing the applicant's Procedures Generation Package the question was raised as to whether the plant-specific technical guidelines adequately reflect plant-specific deviations and additions from the WOG generic technical guidelines. In the event that the Emergency Operating Procedures (EOPs) are revised, the applicant should ensure that the DCRDR task analysis is still valid and, if necessary, any areas that are changed should be rewritten.

### 18.1.3 Control Room Inventory

The control room inventory and its comparison against the information and control needs derived from the system function and task analysis meet the requirements of Supplement 1 to NUREG-0737.

### 18.1.4 Control Room Survey

The control room surveys are complete except for four surveys that must wait for control room construction to be completed (ambient noise; illumination;

heating, ventilation, and air conditioning; and communications). These surveys will be conducted before fuel load. The applicant has to (1) confirm the completion of these surveys and submit for review the preliminary result of the surveys and (2) identify any human engineering discrepancies (HEDs) generated from these surveys as well as provide the proposed resolution and schedule of implementation of corrective action. The staff's concern about the Auxiliary Equipment Panel-1 (AEP-1) was discussed at the meeting at the site and the panel was reviewed at the control room on August 19, 1986. In its letter of August 29, 1986, the applicant confirmed the verbal explanations and clarifications of the work done on the AEP-1.

The applicant reviewed the EOPs to determine which steps required the operator to interface with the AEP-1. Each interface/action of the operator was analyzed to determine whether there were any consequences of either misuse or nonuse of the AEP-1 controls or indicators.

The controls and the indicators were reviewed to determine the safety consequences of their misuse or nonuse, and whether they are the primary control or indicator for the required action. The results of the review were that "excluding the reactor vessel and pressurizer vent valve controls, no safety consequences from misuse or nonuse were discovered."

The reactor vessel and pressurizer vent valve controls are safety related, are well labeled, their knobs have been painted red, and the section of the AEP-1 containing these controls has been clearly demarcated to differentiate the valve controls from the rest of the AEP-1 controls. In addition, these valves have pull-to-lock switches that can only be operated in two separate steps, and these switches are the only pull-to-lock switches on the AEP-1. This is adequate and acceptable.

### 18.1.5 Assessment of Human Engineering Discrepancies

The applicant assessment process as described meets the requirements of Supplement 1 to NUREG-0737. To clarify the staff's concern regarding the cumulative effects of the HEDs, the applicant submitted a discussion of the process used to evaluate cumulative effects of HEDs. The process consisted of grouping the HEDs having the same problem, grouping the HED that addressed the same components, and reassessing the HEDs for probability of error and its consequences to take the proper resolutions of these HEDs. The assessment process is acceptable and meets the requirements of Supplement 1 to NUREG-0737.

### 18.1.6 Selection of Design Improvements

The applicant's process for selecting design improvements is adequate and meets the requirement of Supplement 1 to NUREG-0737.

### 18.1.7 Verification That Design Improvements Provide Necessary Correction and Do Not Introduce New HEDs

The verification program as described by the applicant is acceptable and meets the requirements of Supplement 1 to NUREG-0737.

### 18.1.8 Coordination of the DCRDR With Other NUREG-0737 (Supplement 1) Programs

The applicant's Summary Reports do not describe in sufficient detail the coordination of the control room activities to allow a final conclusion about the adequacy of the applicant's coordination effort.

In its submittal of August 29, 1986, the applicant outlined the activities, participation, and responsibilities of the Lead Discipline Engineer (LDE) and members of the DCRDR team. The LDE was responsible for day-to-day CRDR activities and has the "overall responsibility for ensuring that the review was conducted as planned and scheduled." The coordination of the DCRDR meets the requirements of Supplement 1 to NUREG-0737.

### 18.1.9 Summary

When completed, the DCDR activities will meet the requirements of Supplement 1 to NUREG-0737. However, a license condition shall be included in the license stating that the applicant should submit to the staff for review the final results of the control room survey before startup following the first refueling.

## 18.2* Safety Parameter Display System

All licensees and applicants must provide a safety parameter display system (SPDS) in the control room of their plant. The Commission-approved requirements for the SPDS are defined in Supplement 1 to NUREG-0737.

The purpose of the SPDS is to provide a concise display of critical plant variables to control room operators to aid them in rapidly and reliably determining the safety status of the plant. NUREG-0737, Supplement 1, requires licensees and applicants to prepare a written safety analysis describing the basis on which the selected parameters are sufficient to assess the safety status of each identified function for a wide range of events, which includes symptoms of severe accidents. Licensees and applicants shall also prepare an implementation plan for the SPDS which contains schedules for design, development, installation, and full operation of the SPDS as well as a design verification and validation plan. The safety analysis and the implementation plan are to be submitted to the NRC for staff review. The results from the staff's review are to be published in a Safety Evaluation Report (SER).

The staff reviewed the applicant's safety analysis on the Shearon Harris SPDS and conducted an audit of the Shearon Harris SPDS.

As a result of these activities, the staff concluded that the Shearon Harris SPDS should meet NRC requirements provided the guidance and recommendations made in the SER are followed. In the SER, the staff also required a design modification to the Class 1E multiplexer cards. In addition, the staff expressed a need for the display of additional variables in the SPDS. These additional variables would provide the control room operator with unique inputs in evaluating the status of the critical safety functions. Also, as the SPDS design was incomplete, additional information was needed from the applicant for the staff to

*Previously titled "Planning Phase."

complete its review of the system. The applicant submitted the requested information in its letters dated June 2 and September 2, 1986. The staff evaluated these submittals and identified two license conditions and three confirmatory items which are detailed in this supplement.

The applicant submitted a Safety Analysis Report (SAR) for the SPDS on December 2, 1983. As part of NRC review of the display system, the staff conducted a design verification audit of the SPDS on March 5-7, 1985. The audit was conducted with the assistance of a consultant from Lawrence Livermore National Laboratory (LLNL). Specific findings were documented in the SER. In the conclusion section of the SER, the staff requested specific information additions and design modifications so the SPDS will meet the requirements of Supplement 1 to NUREG-0737. The staff's evaluation of the Shearon Harris SPDS is based on its review of (1) the SAR, (2) staff audit (3) submittals, and (4) discussions with the applicant's representatives during the staff's DCRDR meetings and site visits.

18.2.1 SPDS Description

The SPDS of Shearon Harris is a subunit of the Shearon Harris Emergency Response Facility Information System (ERFIS). Processing of plant parameters by ERFIS is presented on two SPDS terminals within the main control room.

The important parameters for each function have been combined in a logical array called a status tree. The displayed status trees are dynamic and reflect the real time status of the critical safety functions and serve as cognitive aids to the operators.

The applicant's SAR states that

> Since there are a number of parameters of importance to each function, the trees contain several branches and paths. The end point of each path defines a unique set of plant conditions, expressed as a combination of current values of the parameters. Each set of conditions reflects how nearly adequate the critical safety function is satisfied, and thus the priority of the required response. In order to quickly inform the operator of the current conditions, each path is color coded. The color tells the operator immediately if the critical safety function is challenged and tells him of the relative severity of the challenge.

The Shearon Harris SPDS top level display contains six critical safety function boxes. When the operator is displaying a second level status tree, an overview of the key plant parameters is displayed in the general display area. A third level display is available containing sets of predefined variables for trending.

18.2.2 Parameter Selection

Section 4.1.f of Supplement 1 to NUREG-0737 states that:

> The minimum information to be provided shall be sufficient to provide information to plant operators about:
>
> (i) Reactivity control;

(ii) Reactor core cooling and heat removal from the primary system;

(iii) Reactor coolant system integrity;

(iv) Radioactivity control;

(v) Containment conditions.

For review purposes, these five items have been designated as critical safety functions (CSFs).

The applicant has defined its CSFs as follows:

(1) subcriticality
(2) core cooling
(3) RCS integrity
(4) heat sink
(5) containment
(6) RCS inventory

The staff review results follow:

Variable Selection

In the SER, the staff requested that the applicant submit a list which coordinates the SPDS variables with those critical safety functions specified in NUREG-0737, Supplement 1. In addition, the list should contain information which identifies the display format (or page) where the variable is presented to the user.

The applicant submitted the requested information in a cross-referenced table, "Safety Function Variable," in its letter of September 2, 1986. The cross-referenced table was reviewed by the staff. The table lists each safety function, the corresponding variables as per NUREG-0737, and the corresponding parameters. The applicant's response is acceptable as it provides information equivalent to that required by Supplement 1 to NUREG-0737.

Containment hydrogen concentration is a key parameter used in the emergency guidelines to monitor combustible gas control and to indicate a compromise of the "Containment Conditions" safety function. The staff recommended in the SER that containment hydrogen concentration be added to the SPDS, and that the applicant confirm that the following variables are in fact available from the SPDS console.

(1) source-range neutron flux
(2) intermediate-range neutron flux
(3) RHR flow
(4) steam generator (or steamline) radiation
(5) stack radiation
(6) containment isolation.

The applicant stated in its letter of September 2, 1986, that it will add steamline radiation (item 4), stack radiation (item 5) and containment isolation (item 6) variables to the SPDS. The source-range neutron flux, intermediate-range neutron flux, RHR flow (items 1-3), and containment hydrogen concentration variables are available from the SPDS. The staff finds this acceptable.

Design Validation of the SPDS Variables

The applicant described in the SAR a program for verification and validation of the SPDS, including the SPDS variables. The description was not documented and the staff asked the applicant to submit for the staff review:

(1) A description of how the design validation of the SPDS variables will be achieved as part of the Validation Test Plan.

(2) A Validation Test Plan which includes human factors acceptance criteria for evaluating the use of the SPDS.

(3) A Validation Test Report which describes test results and plans for resolution of problems identified during the Test Program.

In its letter of June 2, 1986, the applicant submitted the following answers to the above:

(1) The Critical Safety Function Status Trees derived from the Emergency Response Guidelines (ERGs) form the basis of Shearon Harris SPDS top two level displays. The SPDS status trees system are a part of the integrated plant computer system and the applicant prepared a complete setpoint study and included them in the Procedure Generation Package (PGP). The applicant has performed scenerios on two different simulators and walked through the procedures in table top emergency planning reviews. With the large amount of operator input, review, and the setpoint study, the variables have been verified, tested, validated, and analyzed, and the results show that the actual results matches the expected results.

(2) The applicant submitted a summary of the Validation Test Plan which is reviewed in another section of this supplement.

(3) In its letter of September 2, 1986, the applicant confirmed that the Validation Test Report is approximately 85% complete. The applicant committed to submit this report before startup following the first refueling. A license condition covering this item shall be included in the license.

The applicant's responses are acceptable.

18.2.3 Human Factors Program

The staff's review of this program consisted of an evaluation of the applicant's SAR, an audit of the design process used to develop the display, and an audit of selected display formats within the library of the system.

The staff requested in the SER that the applicant conduct a review of all SPDS display formats for human engineering discrepancies (HEDs). All identified HEDs should be assessed and resolved within the DCRDR effort and the results of the assessment reported in the DCRDR Summary Report which is submitted for staff review. The applicant completed a preliminary review of the SPDS and identified HEDs which have been assessed as a part of the DCRDR effort and were submitted to the NRC as a part of the Summary Report. A final review should be completed and any additional HEDs identified on the SPDS should be resolved before startup following the first refueling outage.

### 18.2.4 Electrical and Electronic Isolation

The SER approved the Shearon Harris isolation device, a fiber-optic cable, to interface the SPDS with safety-related systems. The staff took the position that the Class 1E multiplexer cards within their associated divisions must be powered from the Class 1E power supplies within that division. In its June 2, 1986, letter, the applicant stated that the SPDS design has been modified so that the Class 1E multiplexer cards are powered from Class 1E power supplies within the same division as are the cards. The letter of June 2, 1986, also contained a one-line diagram of the 120-V ac distribution system within safety division "A" and safety division "B" showing the load distribution of the multiplexer card. Before fuel load, the staff will confirm that the modification has been completed.

### 18.2.5 System Availability

The applicant provided a redundant computer configuration to achieve a high availability goal of 99%. As stated in the SER, the methodology and technique used to achieve this goal are acceptable. However, the staff requested that the applicant submit a summary report on the results of the analysis for confirmatory review. The applicant submitted the requested summary report with the conclusion that the calculated availability of the SPDS is 99.87%. The staff reviewed the submittal and finds it satisfactory.

### 18.2.6 Verification and Validation Plan

During the design verification audit, the NRC audit team was presented with an overview of the Verification and Validation (V/V) Program. This overview described the scope, procedures, schedules, and deliverables for the program.

The staff's preliminary evaluation of the plan found the structure and activities within the plan were similar to those of NSAC-39 (Electric Power Research Institute, 1981). In the SER, it was requested that the V/V Plan be docketed as it would serve as a useful reference point for the staff in evaluating results from the program. The applicant submitted a summary of the Verification and Validation Plan (letter dated June 2, 1986) and confirmed that the V/V Team is independent of the Development Team and Quality Assurance Program.

The V/V Plan is based on the NSAC-39 report (EPRI, 1981) which states that the five V/V activities described in the NSAC-39 report and being applied for SPDS/ERFIS include systems requirements verification, system validation, field installation verification, and preparation of the final V/V Report.

### 18.2.7 Implementation Plan

During the design verification audit, the NRC audit team reassessed Shearon Harris' implementation plan for the SPDS. It was noted that many of the activities planned in the SPDS devlopment program were not in the plan and that the activities defined in the plan were not in phase with current activities. The staff requested in the SER that the applicant provide a revised implementation plan to reflect currently planned activities and schedules for the design completion, control room installation, and operation of the SPDS.

In its letter of June 2, 1986, the applicant stated that the design of the SPDS is complete and the SPDS will be operational before fuel load. The staff will confirm this item.

18.2.8 Procedures and Training

During the design verification audit, the NRC team was unable to determine if an operator's training program in the use of the SPDS existed. In the SER, the staff requested that the applicant provide a commitment that procedures which describe the timely and correct safety status assessment when the SPDS is and is not available will be developed and that operators be trained to respond to accident conditions both with and without the SPDS available.

Emergency Operating Procedures (EOPs) of Shearon Harris specify when the critical safety function status trees (CSFST) are to be monitored and when the functional restorative procedures required by the respective states of the CSFST are to be implemented. If the SPDS which has a calculated availability of 99.87% is not available, a hard copy of the CSFST will be available for assessment. The EOPs do not distinguish between the manual or computerized acqusition of the CSFST information since they produce identical results.

The training of the Shift Technical Advisors (primary individuals responsible for evaluating the CSFST) and the licensed operators covered the purpose and use of the CSFST. Also the applicant committed that the operators will be trained on how the SPDS displays are accessed from the control room CRTs (cathode-ray tubes). The applicant's commitment is acceptable.

18.2.9 Conclusions

In its letters of June 2 and September 2, 1986, the applicant answered adequately the concernes of the staff and submitted the information and documentation as requested in the SER.

On the basis of its review, the staff concludes:

(1) The displays are dynamic, reflect the real time status of the critical safety functions, and are useful to the operator.

(2) The key variables and corresponding parameters are acceptable.

(3) An acceptable Verification and Validation Plan is implemented at Shearon Harris SPDS.

(4) The electrical and electronic isolation using fiber-optic cable is adequate and acceptable.

(5) The SPDS calculated availability of 99.87% is satisfactory.

(6) The training of the users of the SPDS is adequate and acceptable.

(7) The applicant's SPDS will satisfy the requirements of Supplement 1 to NUREG-0737.

However, the following license conditions shall be included in the license stating that the applicant should submit to the NRC for review before startup following the first refueling:

(1) The final Validation Test Report.

(2) The resolution of additional HEDs identified on the SPDS.

In addition, before fuel load the staff will confirm that

(1) The SPDS is operational.

(2) Modifications of the SPDS design so the Class 1E multiplexer cards are powered from Class 1E power within their division are completed.

(3) Stack radiation, the steamline radiation, and the containment isolation (Phase A and Phase B) variables have been added to the SPDS.

# 19 REPORT OF THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

## Building Clearances

It was stated in Section 19 of SER Supplement 1 that the staff would address the adequacy of the clearances between adjacent buildings and report its findings in a future supplement. The applicant provided additional information on this matter in its submittal of July 19, 1985. On the basis of its evaluation of Table 1 of the above-cited submittal which listed the clearances between various buildings and the maximum displacements of two adjacent buildings added together at the interface during a safe shutdown earthquake, the staff has concluded that adequate clearances exist between adjacent buildings. Section 19 of Supplement 1 also stated that the staff would further address the essential chilled water system in a future supplement. This matter is discussed in Section 9.2 of this supplement.

APPENDIX A

CONTINUATION OF CHRONOLOGY OF NRC STAFF RADIOLOGICAL REVIEW OF SHEARON HARRIS

| | |
|---|---|
| April 1, 1986 | Letter from applicant forwarding response to October 30, 1985, request for additional information on operability of containment purge and vent valves. |
| April 4, 1986 | Letter from applicant forwarding requested additional information on fire protection. |
| April 21, 1986 | Letter from applicant submitting revised commitment regarding operator requalification training for mitigating core damage. |
| April 22, 1986 | Letter to applicant regarding request for additional information on preservice inspection program relief requests. |
| April 23, 1986 | Letter from applicant submitting additional information on setpoints for PORVs at plant to close out Confirmatory Item 10. |
| April 24, 1986 | Generic Letter 86-10 issued regarding implementation of fire protection requirements. |
| April 25, 1986 | Letter from applicant informing staff that anticipated fuel load date will be late July 1986. |
| April 28, 1986 | Letter to applicant regarding electrical, instrumentation, and control system site audit report. |
| April 28, 1986 | Letter from applicant forwarding Revision 1 to Control Room Design Review (CRDR) Final Summary Report. |
| May 1, 1986 | Letter from applicant forwarding marked-up FSAR pages and clarifying compliance with Regulatory Guide 1.68, Appendix A. |
| May 1, 1986 | Letter from applicant forwarding additional information to September 3, 1985, response to TMI Action Item II.K.3.5. Information should close out SER Confirmatory Item 33. |
| May 2, 1986 | Letter from applicant regarding response to January 6, 1986, request for additional information regarding description of initial test program in facility FSAR. |
| May 2, 1986 | Letter from applicant regarding additional information supplementing March 4, 1986, request for exemption from Section IV.F.1 of Appendix E to 10 CFR 50. |

| | |
|---|---|
| May 8, 1986 | Letter from applicant regarding revised emergency procedures. |
| May 12, 1986 | Letter to applicant regarding fire protection safety evaluation of utility's April 16, 1986, proposal to establish continuous fire watch at fuel handling building. |
| May 12, 1986 | Letter to applicant regarding request for additional information on testing of relief and safety valves, Item II.D.1. |
| May 14, 1986 | Letter to applicant regarding technical evaluation report for Seismic Qualification Review Team and Pump and Valve Operability Review Team. |
| May 14, 1986 | Letter to applicant regarding issuance of Supplement 3 to SER. |
| May 14, 1986 | Letter from applicant regarding additional information on input into final draft Technical Specifications for facility. |
| May 15, 1986 | Letter to applicant regarding summary of site visit on January 28-30, 1986, relating to electrical instrumentation and control systems. |
| May 15, 1986 | Letter from applicant regarding additional information on turbine system maintenance program and requesting SER License Condition 1 be deleted. |
| May 19, 1986 | Letter from applicant regarding justification for revising Technical Specification surveillance intervals. |
| May 19, 1986 | Letter from applicant regarding revised plant emergency procedures. |
| May 19, 1986 | Letter from applicant regarding additional information on postaccident sampling system per License Condition 3. |
| May 22, 1986 | Letter from applicant regarding results of large-break LOCA analysis and radial peaking factor limit report. |
| May 22, 1986 | Letter from applicant forwarding justification of containment isolation HI-1 setpoint pressure. |
| May 22, 1986 | Letter from applicant regarding committing to install permanent test switch to permit use of loss of offsite power signal to initiate diesel generator operation before receipt of full-power license. |
| May 28, 1986 | Letter from applicant forwarding additional information for utility request for deviation from NUREG-0800 requirements for manual safe-shutdown-earthquake hose stations. |
| May 29, 1986 | Letter from applicant forwarding structural integrity test summary report. |

| | |
|---|---|
| May 29, 1986 | Letter from applicant regarding submitting additional information on inadequate core coolant instrumentation. Deletion of SER License Condition 8 is requested. |
| May 30, 1986 | Letter to applicant regarding Offsite Dose Calculation Manual. |
| May 30, 1986 | Letter from applicant regarding additional information on CRDR program, including revised emergency operating procedures. |
| June 2, 1986 | Letter from applicant regarding additional information on reactor coolant system flow uncertainty. |
| June 2, 1986 | Letter from applicant regarding NRC's October 25, 1986, request for additional information on safety parameter display system. Review and issuance of SSER are requested. |
| June 2, 1986 | Letter from applicant regarding permanent exemption to provisions of 10 CFR 50 Appendix J, III.D.2(b)(ii). |
| June 2, 1986 | Letter from applicant regarding additional information on postaccident sampling system in response to SER License Condition 3 and requesting that License Condition 3 be deleted. |
| June 2, 1986 | Letter from applicant forwarding additional information on Phase I of NUREG-0612, control of heavy loads (SER Confirmatory Item 21). |
| June 3, 1986 | Letter from applicant forwarding additional information regarding requests for relief from ASME Code, Section XI. |
| June 3, 1986 | Letter from applicant forwarding additional information on implementation of Revision 1 to Regulatory Guide 1.27. |
| June 3, 1986 | Letter from applicant regarding submittal of additional information on high-energy-line breaks outside containment. |
| June 3, 1986 | Letter from applicant providing additional information supporting nuclear design FQ of 2.28 for facility. |
| June 4, 1986 | Letter from applicant forwarding marked-up FSAR Section 6.2.4 on containment isolation valves. |
| June 5, 1986 | Letter from applicant forwarding Revision 2 to Transamerica Delaval, Inc., diesel generator Design Review and Quality Revalidation Report. |
| June 5, 1986 | Letter from applicant forwarding preliminary FSAR information to aid reviewers in preparation of final draft Technical Specifications and input for SER Supplement 4. |
| June 6, 1986 | Letter from applicant responding to confirmatory items identified in SSER 3 Section 3.10.1. |

| | |
|---|---|
| June 6, 1986 | Letter from applicant forwarding additional information on Item II.D.1 of NUREG-0737 and SER Confirmatory Item 6. |
| June 6, 1986 | Letter to applicant regarding backfit status of proposed Section 3.7.1.3 to Technical Specifications regarding containment purges denying. |
| June 6, 1986 | Letter from applicant regarding additional input to final draft Technical Specifications. |
| June 10, 1986 | Letter to applicant regarding request for additional information on pump and valve testing. |
| June 10, 1986 | Letter from applicant requesting that NRC hold in abeyance March 4, 1986, request for exemption from 10 CFR 50 Appendix E. |
| June 13, 1986 | Letter from applicant revising information provided in utility's April 18, 1986, letter on inadequate core cooling. |
| June 18, 1986 | Letter from applicant forwarding additional deviation to BTP CMEB 9.5-1 of NUREG-0800. |
| June 18, 1986 | Letter from applicant forwarding additional information on electrical equipment. |
| June 20, 1986 | Letter from applicant forwarding Amendment 28 to FSAR. |
| June 25, 1986 | Generic Letter 86-11 issued regarding distribution of products irradiated in research reactors. |
| June 30, 1986 | Letter from applicant forwarding Revision 2 to CRDR final summary report. |
| July 3, 1986 | Letter from applicant forwarding additional information requested in May 12, 1986, NRC letter on testing of safety and relief valves, allowing closeout of SER Confirmatory Item 6 and NUREG-0737 Item II.D.1. |
| July 3, 1986 | Letter from applicant forwarding change 3 to Emergency Response Plan. |
| July 3, 1986 | Generic Letter 86-12 issued regarding authorization to use highly enriched uranium fuel. |
| July 10, 1986 | Letter from applicant requesting that NRC resume active review of March 4, 1986, request for exemption from 10 CFR 50 Appendix E. |
| July 11, 1986 | Letter to applicant requesting that utility certify enclosed draft Technical Specifications. |
| July 16, 1986 | Letter from applicant advising that commitment to reroute electrical conduit serving ex-core neutron detector NM-44 per Draft SER Open Item 99 unnecessary. |

| | |
|---|---|
| July 25, 1986 | Letter from applicant forwarding Amendment 29 to FSAR. |
| July 31, 1986 | Letter from applicant submitting additional information on conformance to 10 CFR 50.61, concerning pressurized thermal shock. |
| July 31, 1986 | Letter from applicant responding to staff's June 10, 1986, request for additional information on pump and valve testing program. |
| August 1, 1986 | Letter from applicant informing staff of distribution of Amendment 29 to FSAR to individuals on distribution list. |
| August 6, 1986 | Letter from applicant forwarding additional information on fire protection, clarifying July 16, 1984, response to Question 410.25 and September 26, 1985, response to NRC Question 410.53a on associated circuits. |
| August 6, 1986 | Letter from applicant forwarding response to request for additional information for relief from Section XI of ASME Code identified in preservice inspection activities. |
| August 8, 1986 | Letter from applicant responding to staff's July 9, 1986, concerns about Amendments 26 and 27 to FSAR. |
| August 20, 1986 | Letter from applicant updating April 28, 1986, licensing issues from timely resolution. |
| August 28, 1986 | Generic Letter 86-14 issued regarding operator licensing exams. |
| August 22, 1986 | Letter from applicant forwarding Revision 32 to FSAR amending Sections 11.5.2.7.13, 11.5.2.7.16, and 11.5.2.7.17. |
| August 27, 1986 | Letter from applicant forwarding analyses and discussions intended to resolve control room habitability following postulated chlorine release accident issue. |
| August 29, 1986 | Letter from applicant forwarding revised distribution list for FSAR Amendment 32. |

APPENDIX B

BIBLIOGRAPHY


Electric Power Research Institute, NSAC 39, "Verification and Validation for Safety Parameter Display Systems," December 1981.

National Institute for Occupational Safety and Health/Occupational Safety and Health Administration, "Pocket Guide to Chemical Hazards," September 1978.

U.S. Nuclear Regulatory Commission, Commission Order CLI-80-12, 11 NRC 514 (April 17, 1980).

---, Generic letter to all operating plants, applicants for operating licenses, and holders of construction permits regarding indicating compliance with NUREG-0612, December 22, 1980.

---, Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events," July 8, 1983.

---, Generic Letter 84-16, "Adequacy of On-Shift Operating Experience for Near-Term Operating License Applicants," June 27, 1984.

---, Generic Letter 85-09, "Technical Specifications for Generic Letter 83-28, Item 43," May 23, 1985.

---, Generic Letter 86-10, "Implementation of Fire Protection Requirements," April 24, 1986.

---, Memorandum dated April 4, 1984, from W. T. Russell to T. M. Novak, "HFEB: (1) SER Input for Shearon Harris 1; (2) Comments on the Applicant's Design Evaluation Report; and (3) In Progress Audit Report."

---, Memorandum dated August 14, 1985, from W. H. Regan, Jr., to G. Knighton, "HFEB Comments on Shearon Harris Unit 1 Detailed Control Room Design Review (DCRDR) Summary Report."

---, NUREG-0452, "Standardized Technical Specifications for Westinghouse Pressurized Water Reactors," Revision 5, to be published.

---, NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," December 1979.

---, NUREG-0570, "Toxic Vapor Concentrations in a Control Room Following a Postulated Accidental Release," 1979.

---, NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," July 1980.

---, NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," October 1981.

---, NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980; Supplement 1 (Generic Letter 82-33), January 1983.

---, NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Section 18.1, Appendix A, "Evaluation Criteria for Detailed Control Room Design Reviews," September 1984.

---, NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures," August 1982.

---, NUREG-1014, "Safety Evaluation Report Related to the D4/D5/E Steam Generator Design Modification," October 1983.

---, NUREG-1216, "Safety Evaluation Report Related to the Operability and Reliability of Emergency Diesel Generators Manufactured by Transamerica Delaval Inc.," August 1986.

---, SECY-82-465, "Pressurized Thermal Shock," November 23, 1982.

U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," January 14, 1980; Supplements, February 29, September 30, and October 24, 1980.

---, IE Bulletin 79-15, "Deep Draft Pump Deficiencies," July 11, 1979.

---, IE Information Notice 79-22, "Qualification of Control Systems," September 19, 1979.

---, Inspection Reports 50-400/86-07, March 14, 1986.
50-400/86-10, March 18, 1986.
50-400/85-16, June 5, 1986.
50-400/86-34, June 2, 1986.

Westinghouse Electric Corp., WCAP-8720, Addendum 3, Revision 1, "Improved Analytical Models Used in Westinghouse Fuel Rod Design Computations Application for Transient Analysis," September 30, 1979.

---, WCAP-9561, Addendum 3, Revision 1, "BART A1: A Computer Code for the Best Estimate Analysis of Reflood Transients," July 24, 1986.

---, WCAP-10698, "SGTR Analysis Methodology to Determine Margin to Steam Generator Overfill," December 1984.

---, WCAP-10698, Supplement 1, "Evaluation of Offsite Radiation Doses for SGTR Accident," May 1985.

---, WCAP-11002, "Evaluation of Steam Generator Overfill Due to SGTR Accidents," February 1986.

Wyle Laboratories, Test Report 47879-06.

## INDUSTRY CODES AND STANDARDS

American National Standards Institute

ANSI Standard N14.6 - 1978, "Standard for Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or More for Nuclear Materials."

ANSI Standard N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants."

ANSI Standard N18.17-1973, "Industrial Security for Nuclear Power Plants."

American Nuclear Society

ANS 3.1-1979 (September draft), "Selection, Qualification, and Training of Personnel for Nuclear Power Plants."

ANS 3.2-1982, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants."

American Society of Mechanical Engineers

ASME Boiler and Pressure Vessel Code, Section XI, 1980 Edition with Addenda through Winter 1982.

Institute of Electrical and Electronics Engineers

Standard 323-1974, "Qualifying Class 1E Equipment for Nuclear Power Generating Stations."

Standard 323-1983, "Qualifying Class 1E Equipment for Nuclear Power Generating Stations."

Standard 334-1971, "Standard for Type Test of Continuous Duty Class 1E Motors for Nuclear Power Generating Stations."

Standard 344-1975, "Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations."

Standard 382-1972, "Standard for Qualification of Safety-Related Valve Actuators."

Standard 383-1974, "Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connects for Nuclear Power Generating Station."

Standard 384-1974, "Standard Criteria for Independence of Class 1E Equipment and Circuits."

American Society for Testing And Materials

Standard ASTM E-119-1983, "Standard Methods of Fire Tests of Building Construction and Materials."

## APPENDIX D

## ACRONYMS AND INITIALISMS

| | |
|---|---|
| ACP | auxiliary control panel |
| ACRS | Advisory Committee on Reactor Safeguards |
| AFW | auxiliary feedwater |
| AFWS | auxiliary feedwater system |
| ALARA | as low as reasonably achievable |
| ANS | American Nuclear Society |
| ANSI | American National Standards Institute |
| APDMS | axial power distribution monitoring system |
| ASLB | Atomic Safety and Licensing Board |
| ASME | American Society of Mechanical Engineers |
| BMEP | brake mean effective pressure |
| BNP | Brunswick Nuclear Project |
| BOC | beginning of cycle |
| BOP | balance of plant |
| BTP | Branch Technical Position |
| BWR | boiling-water reactor |
| CAT | Construction Appraisal Team |
| CCW | component cooling water |
| CFR | Code of Federal Regulations |
| CFSGOG | Counter Flow Steam Generator Owners Group |
| CHR | containment heat removal |
| CIV | containment isolation valve |
| CP&L | Carolina Power and Light Company (the applicant) |
| CQA | Corporate Quality Assurance |
| CRT | cathode-ray tube |
| CSFST | critical safety function status tree |
| DECLG | double-ended cold-leg guillotine |
| DNBR | departure from nucleate boiling ratio |
| DOE | Department of Energy |
| DR | design review |
| EAL | Emergency Action Level |
| ECAPM | excore axial power |
| ECC | emergency core cooling |
| ECCS | emergency core cooling system |
| EDG | emergency diesel generator |
| EOC | end of cycle |
| EOP | Emergency Operating Procedures |
| EPRI | Electric Power Research Institute |
| ERFIS | Emergency Response Facility Information System |
| ERGs | Emergency Response Guidelines |

| | |
|---|---|
| ESCWS | essential services chilled water system |
| ESF | engineered safety feature |
| ESW | emergency service water |
| ESWI | emergency service water intake |
| ESWD | emergency service water discharge |
| FSAR | Final Safety Analysis Report |
| FW | feedwater |
| GDC | General Design Criterion(a) |
| GET | general employee training |
| GL | Generic Letter |
| HED | human engineering discrepancy |
| HELB | high-energy-line break |
| HHSI | high-head safety injection |
| HNP | Harris Nuclear Project |
| HVAC | heating, ventilation, and air conditioning |
| ICC | inadequate core cooling |
| ICCI | inadequate core cooling instrumentation |
| IDI | Independent Design Inspection |
| IE | Office of Inspection and Enforcement |
| IEEE | Institute of Electrical and Electronics Engineers |
| ILRT | integrated leak rate test |
| INEL | Idaho National Engineering Laboratory |
| ISI | inservice inspection |
| IST | inservice testing |
| JTG | Joint Test Group |
| LBLOCA | large-break loss-of-coolant accident |
| LHSI | low-head safety injection |
| LLRT | local leak rate test |
| LOCA | loss-of-coolant accident |
| MEPL | Material, Equipment and Parts List |
| M/S | maintenance and surveillance |
| MSIS | main steam isolation signal |
| msl | mean sea level |
| MSLB | main steamline break |
| MT | magnetic particle testing |
| MTC | moderator temperature coefficient |
| NGG | Nuclear Generation Group |
| NIOSH | National Institute for Occupational Safety and Health |
| NRC | U.S. Nuclear Regulatory Commission |
| NRR | Office of Nuclear Reactor Regulation |
| NSES | Nuclear Safety and Environmental Services |
| NSSS | nuclear steam supply system |
| OG | Owners Group |
| OL | operating license |
| OSG | Operations Support Group |

| | |
|---|---|
| OSHA | Occupational Safety and Health Administration |
| OT | Operations Training |
| PASS | postaccident sampling system |
| PCT | peak cladding temperature |
| PGP | Procedures Generation Package |
| PMP | probable maximum precipitation |
| PNL | Pacific Northwest Laboratory |
| PNSC | Plant Nuclear Safety Committee |
| PORV | power-operated relief valve |
| PSE&C | Power Supply and Engineering and Construction |
| PSI | preservice inspection |
| P-STGs | Plant-Specific Technical Guidelines |
| PTS | pressurized thermal shock |
| PVORT | Pump and Valve Operability Review Team |
| PWR | pressurized-water reactor |
| QA | quality assurance |
| QC | quality control |
| QR | quality revalidation |
| RCCA | rod cluster control assembly |
| RCP | reactor coolant pump |
| RCS | reactor coolant system |
| RETS | Radiological Effluent Technical Specifications |
| RG | regulatory guide |
| RHR | residual heat removal |
| RO | reactor operator |
| RTB | reactor trip breaker |
| RVLIS | reactor vessel level instrumentation system |
| SALP | Systematic Assessment of Licensee Performance |
| SCBA | self-contained breathing apparatus |
| SER | Safety Evaluation Report |
| SEVP | Senior Executive Vice President |
| SG | steam generator |
| SGAS | steam generator available signal |
| SGTR | steam generator tube rupture |
| SHNPP | Shearon Harris Nuclear Power Plant Units 1 and 2 |
| SPDS | safety parameter display system |
| SQRT | Seismic Qualification Review Team |
| SRO | senior reactor operator |
| SRP | Standard Review Plan |
| SSE | safe shutdown earthquake |
| STA | shift technical advisor |
| STS | Standard Technical Specifications |
| SV | safety valve |
| TDI | Transamerica Delaval, Inc. |
| TER | Technical Evaluation Report |
| TMI | Three Mile Island |
| TS | Technical Specifications |

| | |
|---|---|
| UVTA | undervoltage trip attachment |
| VV | validation/verification |
| W | Westinghouse |

## APPENDIX E

## NRC STAFF CONTRIBUTORS AND CONSULTANTS

The following NRC staff members were principal contributors to this supplement.

| Name | Branch (Division) |
|---|---|
| G. Bagchi | Engineering (PWR-A)* |
| H. Balukjian | Reactor Systems (PWR-A)* |
| W. L. Belke | Quality Assurance** |
| H. L. Brammer | Engineering (PWR-A)* |
| L. A. Brown | Plant Systems (PWR-A)* |
| O. P. Chopra | Electrical, Instrumentation and Control Systems (PWR-A)* |
| B. Clayton | Facility Operations (PWR-A)* |
| L. P. Crocker | Facility Operations (PWR-A)* |
| M. S. Dunenfeld | Reactor Systems (PWR-A)* |
| B. J. Elliot | Engineering (PWR-A)* |
| R. Fell | Plant Systems (PWR-A)* |
| P. E. Frederickson | Region II |
| C. E. Gaskin | Safeguards Reactor and Transportation Licensing (Safeguards)† |
| R. J. Giardina | Plant Systems (PWR-A)* |
| P. J. Gill | Electrical, Instrumentation and Control Systems (PWR-A)* |

*Office of Nuclear Reactor Regulation.
**Office of Inspection and Enforcement.
†Office of Nuclear Material Safety and Safeguards.

| Name | Branch (Division) |
|---|---|
| R. O. Gonzales | Engineering (PWR-A)* |
| Y. S. Huang | Engineering (PWR-A)* |
| D. Jeng | Engineering (PWR-A)* |
| G. Johnson | Engineering (PWR-A)* |
| R. Kirkwood | Regulatory Improvements (Safety Review and Oversight)* |
| J. E. Knight | Electrical, Instrumentation and Control Systems (PWR-A)* |
| J. L. Koontz | Maintenance Training (Human Factors Technology)* |
| G. W. Lapinsky, Jr. | Facility Operations (PWR-A)* |
| D. Lasher | Electrical, Instrumentation and Control Systems (PWR-A)* |
| W. T. Lefave | Plant Systems (PWR-A)* |
| H. C. Li | Electrical, Instrumentation and Control (BWR)* |
| C. Y. Li | Plant Systems (PWR-A)* |
| R. B. Licciardo | Plant Systems (PWR-A)* |
| R. Lobel | Reactor Systems (PWR-A)* |
| L. Lois | Reactor Systems (PWR-A)* |
| W. C. Lyon | Reactor Systems (PWR-A)* |
| B. Mann | Reactor Systems (PWR-A)* |
| A. S. Masciantonio | Engineering (PWR-A)* |
| J. L. Mauck | Electrical, Instrumentation and Control Systems (PWR-A)* |
| G. F. Maxwell | Region II |
| F. Orr | Facility Operations (PWR-A)* |
| J. C. Pulsipher | Engineering (PWR-A)* |

*Office of Nuclear Reactor Regulation.

| Name | Branch (Division) |
|---|---|
| T. R. Quay | Plant Systems (PWR-A)* |
| F. Rinaldi | Engineering (PWR-A)* |
| O. O. Rothberg | Regulatory Improvements (Safety Review and Oversight)* |
| N. S. Saba | Electrical, Instrumentation and Review (PWR-A)* |
| J. Shapaker | Plant Systems (PWR-A)* |
| A. Singh | Plant Systems (PWR-A)* |
| T. Sullivan | Plant Systems (PWR-A)* |
| N. H. Wagner | Plant, Electrical, Instrumentation and Control Systems (PWR-B)* |
| H. Walker | Electrical, Instrumentation and Control Systems (PWR-A)* |
| J. J. Watt | Reactor Systems (PWR-A)* |
| S. H. Weiss | Electrical, Instrumentation and Control Systems (PWR-A)* |
| K. S. West | Plant Systems (PWR-A)* |
| J. N. Wilson | Reactor Systems (PWR-A)* |

The following laboratories contributed to this supplement.

EG&G Idaho, Inc.
Idaho National Engineering Laboratory
Lawrence Livermore National Laboratory

*Office of Nuclear Reactor Regulation.

# APPENDIX J

## SAFETY EVALUATION OF PRESERVICE INSPECTION RELIEF REQUEST

CAROLINA POWER AND LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1
DOCKET NUMBER 50-400

SAFETY EVALUATION REPORT SUPPLEMENT
PRESERVICE INSPECTION RELIEF REQUEST EVALUATION

# I. INTRODUCTION

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

For nuclear power facilities whose construction permit was issued on or after July 1, 1974, 10 CFR 50.55a(g)(3) specifies that components shall meet the preservice examination requirements set forth in editions and addenda of Section XI of the ASME Boiler and Pressure Vessel Code applied to the construction of the particular component. The provisions of 10 CFR 50.55a(g)(3) also state that components (including supports) may meet the requirements set forth in subsequent editions and addenda of this Code which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein.

In a submittal dated January 7, 1986, the Applicant requested relief from ASME Code Section XI requirements which he has determined to be not practical. As a result of discussions with the Applicant and the staff's request for additional information dated April 22, 1986, this document was revised and resubmitted June 2, 1986, with further revisions submitted August 6, 1986. The updated submittals deleted some of the relief requests and contained clarification along with new and revised requests for relief which were supported by information pursuant to 10 CFR 50.55a(a)(3). Therefore, the staff evaluation consisted of reviewing this submittal to the requirements of the applicable Code edition and addenda and determining if relief from the Code requirements was justified.

## II. TECHNICAL REVIEW CONSIDERATIONS

A. The construction permit for Shearon Harris Nuclear Power Plant, Unit 1 was issued on January 27, 1978. In accordance with 10 CFR 50.55a(g)(3), components (including supports), which are classified as ASME Code Class 1 and 2, have been designed and provided with access to enable the performance of required preservice examinations.

B. Verification of as-built structural integrity of the primary pressure boundary is not dependent on the Section XI preservice examination. The applicable construction codes to which the primary pressure boundary was fabricated contain examination and testing requirements which by themselves provide the necessary assurance that the pressure boundary components are capable of performing safely under all operating conditions reviewed in the FSAR and described in the plant design specification. As a part of these examinations, all of the primary pressure boundary full penetration welds were volumetrically examined (radiographed) and the system was subjected to hydrostatic pressure tests.

C. The intent of a preservice examination is to establish a reference or baseline prior to the initial operation of the facility. The results of subsequent inservice examination can then be compared with the original condition to determine whether changes have occurred. If the inservice inspection results show no change from the original condition, no action is required. In the case where baseline data are not available, all flaws must be treated as new flaws and evaluated accordingly. Section XI of the ASME Code contains acceptance standards which may be used as the basis for evaluating the acceptability of such flaws.

D. Other benefits of the preservice examination include providing redundant or alternative volumetric examination of the primary pressure boundary using a test method different from that employed during the component fabrication. Successful performance of the preservice examination also demonstrates that the welds so examined are capable of subsequent inservice examination using a similar test method.

In the case of Shearon Harris Nuclear Power Plant Unit 1, a large portion of the preservice examination required by the ASME Code was performed. Failure to perform a 100% preservice examination of the welds identified below will not significantly affect the assurance of the initial structural integrity.

E. In some instances where the required preservice examinations were not performed to the full extent specified by the applicable ASME Code, the staff may require that these examinations or supplemental examinations be conducted as a part of the inservice inspection program. Requiring supplemental examinations to be performed at this time would result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. The performance of supplemental examinations, such as surface examinations, in areas where volumetric examination is difficult will be more meaningful after a period of operation. Acceptable preoperational integrity has already been established by similar ASME Code Section III fabrication examinations.

In cases where parts of the required examination areas cannot be effectively examined because of a combination of component design or current examination technique limitations, the development of new or improved examination techniques will continue to be evaluated. As improvements in these areas are achieved, the staff will require that these new techniques be made a part of the inservice examination requirements for the components or welds which received a limited preservice examination.

Several of the preservice inspection relief requests involve limitations to the examination of the required volume of a specific weld. The inservice inspection (ISI) program is based on the examination of a representative sample of welds to detect generic service-induced degradation. In the event that the welds identified in the PSI relief requests are required to be examined again, the possibility of augmented inservice inspection will be evaluated during review of the Applicant's initial 10-year ISI program. An augmented program may include increasing the extent and/or frequency of examination of accessible welds.

## III. EVALUATION OF RELIEF REQUESTS

The Applicant requested relief from specific preservice inspection requirements in a submittal dated January 7, 1986. As a result of discussions with the Applicant and the staff's request for additional information dated April 22, 1986, this document was revised and resubmitted June 2, 1986, with further revisions submitted August 6, 1986. The updated submittals deleted several of the relief requests and contained clarification along with new and revised requests for relief which were supported by information pursuant to 10 CFR 50.55a(a)(3). Based on the information submitted by the Applicant and the staff's review of the design, geometry, and materials of construction of the components, certain preservice inspection requirements of the ASME Boiler and Pressure Vessel Code, Section XI have been determined to be impractical to perform. The Applicant has demonstrated that either (i) the proposed alternative would provide an acceptable level of quality and safety or (ii) compliance with the specified requirements of this section would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(3), conclusions that these preservice requirements are impractical are justified as follows. Unless otherwise stated, references to the Code refer to the ASME Code, Section XI, 1980 Edition including Addenda through Winter 1982.

A. Request for Relief No. R1-001, Examination Category B-J, Item B9.11, Pressure Retaining Piping Welds

Request for Relief No. R1-001 has been deleted due to permanent hanger removal and the required ASME Section XI Code examinations being performed.

B. Request for Relief No. R1-002, Class 1 Snubbers, Examination Category F-C, Item F3.50, Component Standard Supports

Relief Request No. R1-002 has been deleted as the Manufacturer's records of functional tests of snubbers are being used for PSI in accordance with Section XI, paragraph IWB-2200. Therefore, relief is not required.

C. Request for Relief No. R1-003, Examination Category B-J, Item B9.11, Pressure Retaining Circumferential Welds, and Item B9.31, Branch Pipe Connection Welds

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-J, Items B9.11 and B9.31 require a 100% surface and volumetric examination on Class 1 circumferential piping welds and on Class 1 branch pipe connection welds 4 inch and greater nominal pipe size.

Code Relief Request: Relief is requested from examining 100% of the Code-required volume on the 76 circumferential piping welds and the 15 branch connection welds listed in the Table attached to Request for Relief No. R1-003.

Reason for Relief: The Applicant reports that piping weld configurations (Reducer-to-Tee, Pipe-to-Tee, Pipe-to-Flange, etc.) are not conducive for a 100% volumetric examination from both sides of the weld, as required by the Code. Some arrangements and details of the piping systems and components were designed and fabricated before the access and examination requirements of Code Section XI, and especially the requirements of Code Case N-335 could be applied. Consequently some examinations are limited or not practical due to geometric configuration or accessibility. The limitations exist at fitting-to-fitting joints, where geometry and sometimes surface condition preclude ultrasonic coupling, or access for the required scan length.

The Applicant also reported that examination in limited areas was accomplished as a "best effort" attempt to cover as much of the Code-required area or volume as possible. However, the extent of examination coverage in the base metal of the fitting or component cannot be specifically quantified as being 100%. The areas where a complete 100% examination could not be achieved were indicated and noted, along with the limitation, on the data sheets.

It is also reported that these welds all received the ASME Code Section III volumetric and surface examinations during fabrication, and that no impact on plant quality, safety, or reliability is expected as the systems will be subject to system leakage pressure tests and will be visually (VT-2) examined during refueling outages.

Staff Evaluation: The staff has reviewed the information submitted in Request for Relief No. R1-003, including the attached Table which lists the weld for which relief is being requested, the weld configuration, the Code requirement, the type of examination for which relief is requested, and the approximate percentage of the Code-required examination that was completed.

The staff also notes that complete examinations which met the requirements of ASME Code Section XI were performed on welds of similar configuration using the same inspection techniques, equipment, and procedures as those partially inspected or uninspected welds. Since the partially inspected or uninspected welds will see the same operating and environmental conditions as the inspected welds, a reasonable assurance of the structural integrity of the welds for which relief is requested has been attained. Also, all of the subject welds received the ASME Code Section III volumetric and surface examination during fabrication.

Based on the above review, the staff has concluded that the Section III fabrication examinations, supplemented by the Section XI surface examination and the limited Section XI volumetric examination, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

D. Request for Relief No. R1-004, Examination Category B-A, Items B1.11, B1.12, B1.21, B1.22, and B1.40, Pressure Retaining Welds in Reactor Vessel, and Examination Category B-B, Items B2.11 and B2.40, Pressure Retaining Welds in Vessels other than Reactor Vessels

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-A, Items B1.11, B1.12, B1.21, and B1.22 (RPV head and shell welds) require a 100% volumetric examination, Item B1.40 (RPV head-to-flange weld) requires both a 100% volumetric and surface examination. Examination Category B-B, Item B2.11 (Pressurizer circumferential shell-to-head welds) and Item B2.40 (Steam Generator tubesheet-to-head weld) both require a 100% volumetric examination.

Code Relief Request: Relief is requested from examining 100% of the Code-required volume on the 12 Reactor Pressure Vessel welds, 4 Pressurizer welds, and 3 Steam Generator welds listed in the Table submitted in Request for Relief No. R1-004.

Reason for Relief: The Applicant reports that the subject welds were examined to the maximum extent possible as the design of the components presented obstructions (i.e. welded plates, supports, nozzle interference, manways, lifting lugs, etc.) that did not allow the 100% volumetric examination to be performed.

It was also reported that the subject welds received the ASME Code Section III volumetric and surface examinations during fabrication and that the welds will be subject to a system pressure test (VT-2 examination) to the maximum extent possible after each refueling outage. Therefore, no impact on overall plant quality, safety, or reliability is expected.

Staff Evaluation: The staff has reviewed the Applicant's submittal, including the Table identifying the items for which relief is being requested. This Table identifies the component and weld identification, the component design, the Code-requirement for which relief is being requested, the examination angle and technique being used, the specific obstruction which limits the examination, and the estimated percentage of the Code-required examination that was completed. The staff notes that the 4 Pressurizer welds and the 3 Steam Generator welds all received 90% or greater of the Code-required examination. Of the 12 Reactor Pressure Vessel welds, 7 received greater than 93%, 4 received greater than 78%, and 1 weld received 48% of the Code-required examination.

Based on the above review, the staff has concluded that a significant percentage of the Code-required examination has been performed and that these components would have to be redesigned in order to complete the remainder. Therefore, the staff concludes that the limited Section XI volumetric examinations and the Section III fabrication examinations, along with the hydrostatic test, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

E. Request for Relief No. R1-05(A), Examination Category B-M-2, Item B12.50, Valve Bodies Exceeding 4 Inch Nominal Pipe Size

Request for Relief No. R1-05(B), Examination Category B-L-2, Item B12.20, Pump Casings

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-M-2, Item B12.50, Class 1 Valve Bodies exceeding 4 inch nominal pipe size and Examination Category B-L-2, Item B12.20, Class 1 Pump Casings, both require a 100% visual (VT-3) examination for PSI.

Code Relief Request: Relief is requested from performing the preservice visual examination (VT-3) of the internal surfaces of Class 1 Valve Bodies exceeding 4 inch nominal pipe size and of the internal surfaces of the Class 1 Pump Casings listed in the Tables attached to Request for Relief Nos. R1-05(A) and R1-05(B).

Reason for Relief: To perform visual examinations on the internal surfaces of these pumps and valves would require disassembly. It is the Applicant's position that this disassembly process would be a hardship, without any appreciable compensating increase in the level of quality and safety. All the subject pumps and valves have already undergone more stringent examinations (both volumetric and surface) as part of the Section III fabrication process. In addition, all of the subject pumps and valves were visually examined prior to installation into their respective systems and the disassembly and reassembly of essentially new components may cause unnecessary damage.

Staff Evaluation: The staff has reviewed the Applicant's submittal, including the Tables identifying the items for which relief is being requested, and determined that disassembly of pumps and valves at this time, for the sole purpose of performing preservice visual examination using qualified personnel, would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The staff has concluded that the construction Code examinations and tests exceed the requirements for visual examination and, therefore, are an acceptable alternative to the Section XI preservice visual examination.

F. Request for Relief No. R1-006, Examination Category B-D, Items B3.90, B3.110, and B3.130, Full Penetration Welds of Nozzles in Vessels, and Examination Category B-F, Item B5.40, Pressure Retaining Dissimilar Metal Welds

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-D, Items B3.90, B3.110, and B3.130 require a 100% volumetric examination on full penetration nozzle welds in Class 1 vessels. Examination Category B-F, Item B5.40 requires both a 100% surface and volumetric examination on Class 1 pressure retaining dissimilar metal welds.

Code Relief Request: Relief is requested from examining 100% of the Code-required volume on the 23 full penetration nozzle-to-vessel welds and the 6 dissimilar metal welds (29 welds total) listed in the Table submitted August 6, 1986 as part of Request for Relief No. R1-006.

Reason for Request: In order to obtain 100% of the Code-required volume, the ultrasonic examination should be completed from both sides of the weld. The Applicant reports that due to the nozzle configuration, the examination was limited to the shell-side of the nozzle welds and that the shell-side examinations were limited, somewhat, due to obstructions (insulation tabs, heater obstructions, etc.). The pressurizer nozzle to safe-end butt weld examinations were limited due to nozzle configuration and insulation tab obstructions. The areas where complete examination of the Code-required volume could not be achieved were noted on the examiner's data sheets as to the extent and cause.

The Applicant also reported that all of the subject welds examinations during fabrication and were also hydrostatically tested at design temperatures and pressures.

Staff Evaluation: The staff has reviewed the Applicant's submittal, including the Table identifying the items for which relief is being requested. This Table identifies the component and weld identification, the component design, the Code-requirement for which relief is being requested, the examination angle and technique being used, the specific cause for the limitation to the examination, and the approximate extent of the Code-required examination that was completed. The staff notes that ?5 of the subject welds received approximately 50% of the Code-required examination and the remaining 4 welds all received at least 88% of the Code-required examination.

Based on this review, the staff has concluded that a significant percentage of the Code-required examination has been performed and that these components would have to be redesigned in order to complete the remainder. Therefore, the staff concludes that the limited Section XI volumetric examinations and the Section III fabrication examinations, along with the hydrostatic test, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

G. Request for Relief No. R1-007, Examination Category B-J, Item B9.31, Branch Pipe Connection Welds: Request for Relief No. R1-007 has been deleted and the welds previously listed as part of this relief request have been added to Request for Relief No. R1-003.

H. Request for Relief No. R1-008, Examination Category B-H, Item No. B8.20, Pressurizer Integrally Welded Attachments

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-H, Item B8.20 requires a 100% surface or volumetric examination, as applicable, on Class 1 integrally welded attachments to the Pressurizer.

Code Relief Request: Relief is requested from examining 100% of the Code-required surface area on the 8 Pressurizer integrally welded attachments listed in the Table attached to Request for Relief No. R1-008.

Reason for Relief: The design of the subject Pressurizer integrally welded attachments does not allow access to 1/2 inch of the base material past the top end of the welds to facilitate 100% of the Code-required surface examination.

The Applicant reports that the subject welds received the ASME Code Section III surface examination during fabrication.

Staff Evaluation: The staff has reviewed the Applicant's submittal, including the Table identifying the integrally welded attachments for which relief is being requested and the Pressurizer Support Bracket Obstruction Sketch showing the limitation to examination.

Based on this review, the staff has concluded that a significant percentage of the Code-required examination has been performed and that these integrally welded attachments would have to be redesigned in order to complete the remainder. Therefore, the staff concludes that the limited Section XI surface examination and the Section III fabrication surface examination provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

I. <u>Request for Relief No. R1-009, Examination Category B-G-2, Item B7.60, Pressure Retaining Bolting, 2 Inch and Less in Diameter</u>

Relief Request R1-009 has been deleted due to the component obstructions being removed for other plant activities, and the required ASME Section XI Code-requirements being completed.

J. <u>Request for Relief No. R2-001, Examination Category C-F, Item C5.21, Pressure Retaining Welds in Piping, and Examination Category C-C, Items C3.20 and C3.30, Integrally Welded Attachments for Vessels, Piping, Pumps, and Valves</u>

<u>Code Requirement</u>: Section XI, Table IWC-2500-1, Examination Category C-F, Item C5.21 requires a 100% surface and volumetric examination on Class 2 circumferential piping welds greater than 1/2 inch nominal wall thickness.

Section XI, Table IWC-2500-1, Examination Category C-C, Items C3.20 and C3.30 requires a 100% surface examination on Class 2 piping and pump integrally welded attachments whose base material design thickness is 3/4 inch or greater.

<u>Code Relief Request</u>: Relief is requested from examining 100% of the Code-required surface area and/or volume on the 4 circumferential piping welds (Item C5.21) and the 15 integrally welded attachments (Items C3.20 and C3.30) listed in the Table submitted in Request for Relief No. R2-001.

Note: Relief is also requested from examining 100% of the required surface area or volume on 10 circumferential piping welds (also listed in the Table) that the Applicant selected as an augmented examination in response to NRC Question 250.1. This augmented examination requires a sample of welds in the ECCS, CHR, and RHR systems to be examined.

Reason for Relief: Component configurations (pump, valves) and/or structural obstructions (hangers, saddle plates, support structures, etc.) do not permit a 100% surface and/or volumetric examination. The subject components received the ASME Code Section III surface and/or volumetric examinations, as applicable, during fabrication, and hydrostatic tests were performed at design temperatures and pressures.

Staff Evaluation: The staff has reviewed the Applicant's submittal, including the Table identifying the components for which relief is being requested and also the Applicant's sketches showing the limitations to examination.

Based on this review, the staff has concluded that a significant percentage of the Code-required examinations have been performed and that these components would have to be redesigned in order to complete the remainder. Therefore, the staff concludes that the limited Section XI examinations and the Section III fabrication examinations provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

Note: With regards to the request for relief from the augmented examination requirement, the staff notes that, the Applicant has committed to perform 1,064 augmented examinations (525 surface and 539 volumetric) in the ECCS, CHR, and RHR systems. Of the total population of welds in these systems, the sample size is in excess of 10% of the total number of welds. Therefore, the staff considers the intent of the augmented examination to be met and the request for relief granted.

K. Request for Relief No. R2-002, Class 2 Snubbers, Examination Category F-C, Item F3.50, Component Standard Supports

Relief Request No. R2-002 has been deleted as the Manufacturer's records of functional tests of snubbers are being used for PSI in accordance with Section XI, paragraph IWC-2200. Therefore, relief is not required.

L. Request for Relief No. R2-003, Examination Category C-F, Item C5.21, Pressure Retaining Circumferential Piping Welds

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-F, Item C5.21 requires a 100% surface and volumetric examination on Class 2 circumferential piping welds greater than 1/2 inch nominal wall thickness.

Code Relief Request: Relief is requested from examining 100% of the Code-required volume on the 46 circumferential piping welds listed in the Table attached to Request for Relief No. R2-003.

Note: Relief is also requested from examining 100% of the required volume on 124 circumferential piping welds (also listed in the Table) that the Applicant selected as an augmented examination in response to NRC Question 250.1. This augmented examination requires a sample of welds in the ECCS, CHR, and RHR systems to be examined.

Relief is also requested from examining 100% of the required volume on 31 circumferential piping welds (also listed in the Table) that the Applicant selected as an augmented examination for high-energy fluid system piping between containment isolation valves.

Reason for Relief: The Applicant reports that, piping weld configurations (Reducer-to-Tee, Pipe-to-Tee, Pipe-to-Flange, etc.) are not conducive for a 100% volumetric examination as required by the Code. Some arrangements and details of the piping systems and components were designed and fabricated before the access and examination requirements of Code Section XI, and especially the requirements of Code Case N-335 could be applied. Consequently, some examinations are limited or not practical due to geometric configuration or accessibility. The limitations exist at fitting-to-fitting joints, where geometry and sometimes surface condition preclude ultrasonic coupling, or access for the required scan length.

The Applicant also reported that, in most cases, examination in limited areas was accomplished as a "best effort" attempt to cover as much of the Code-required area or volume as possible. However, the extent of examination coverage in the base metal of the fitting or component cannot be specifically quantified as being 100%. The areas where a complete 100% examination could not be achieved were indicated and noted, along with the limitation, on the data sheets.

It is also reported that these welds all received the ASME Code Section III volumetric examination during fabrication.

Staff Evaluation: The staff has reviewed the information submitted in Request for Relief No. R2-003, including the attached Table which lists the weld for which relief is being requested, the weld configuration, the Code or Augmented examination requirement, the type of examination for which relief is requested, and the approximate percentage of the Code-required examination that was completed.

The staff also notes that complete examinations which met the requirements of ASME Code Section XI were performed on welds of similar configuration using the same inspection techniques, equipment, and procedures as those partially inspected or uninspected welds. Since the partially inspected or uninspected welds will see the same operating and environmental conditions as the inspected welds, a reasonable assurance of the structural integrity of the welds for which relief is requested has been attained. Also, all of the subject welds received the ASME Code Section III volumetric examination during fabrication.

Based on the above review, the staff has concluded that the Section III fabrication examinations, supplemented by the Section XI surface examination and the limited Section XI volumetric examination, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

Note: With regards to the request for relief from the augmented examination requirements, the staff notes that, the Applicant has committed to perform 1,064 augmented examinations (525 surface and 539 volumetric) in the ECCS, CHR, and RHR systems. Of the total population of welds in these systems, the sample size is in excess of 10% of the total number of welds. Therefore, the staff considers the intent of the augmented examination to be met and the request for relief granted.

M. <u>Request for Relief No. R2-004, Examination Category C-F, Items C5.11 and C5.21, Pressure Retaining Welds in Piping</u>

<u>Code Requirement</u>: Section XI, Table IWC-2500-1, Examination Category C-F, Item C5.11 requires a 100% surface examination on Class 2 circumferential pressure retaining piping welds 1/2 inch or less nominal pipe thickness, and Item C5.21 requires both a 100% surface and volumetric examination on Class 2 circumferential pressure retaining piping welds greater than 1/2 inch nominal wall thickness.

<u>Code Relief Request</u>: Relief is requested from performing the Code-required volumetric and/or surface examination on the 26 Code Item C5.11 and C5.21 welds listed in the Table attached to Request for Relief No. R2-004.

Note: Relief is also requested from performing the required volumetric examination on the 8 circumferential piping welds (also listed in the Table) the Applicant selected as an augmented examination in response to NRC Question 250.1. This augmented examination requires a sample of welds in the ECCS, CHR, and RHR systems to be examined.

Relief is also requested from performing the required surface examination on the 4 circumferential piping welds (also listed in the Table) the Applicant selected as an augmented examination for high-energy fluid system piping between containment isolation valves.

<u>Reason for Relief</u>: The Applicant reports that, all of the subject component welds are located inside of containment penetrations (flued heads, valve chambers, etc.) and are therefore inaccessible for performing the required examinations.

The Applicant also reports that, the subject welds received the ASME Code Section III volumetric examination and that system hydrostatic/leakage pressure tests will be performed as required to ensure structural integrity. In addition, Primary Reactor Containment Leakage Testing (ILRT/LLRT), per 10 CFR 50 Appendix J, will be performed.

Staff Evaluation: The staff has reviewed the Applicant's submittal, including the Table identifying the welds for which relief is being requested and the Figures showing the flued head and valve chamber design.

The staff also notes that complete examinations which met the requirements of ASME Code Section XI were performed on welds of similar configuration using the same inspection techniques, equipment, and procedures as the subject uninspected welds. Since the uninspected welds will see the same operating and environmental conditions as the inspected welds, a reasonable assurance of the structural integrity of the welds for which relief is requested has been attained. Also, all of the subject welds received the ASME Code Section III volumetric examination during fabrication.

Based on the above review, the staff has concluded that the Section III fabrication examinations and the system hydrostatic/leakage pressure tests provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

Note: With regards to the request for relief from the augmented examination requirements, the staff notes that, the Applicant has committed to perform 1,064 augmented examinations (525 surface and 539 volumetric) in the ECCS, CHR, and RHR systems. Of the total population of welds in these systems, the sample size is in excess of 10% of the total number of welds. Therefore, the staff considers the intent of the augmented examination to be met and the request for relief granted.

N. Request for Relief No. R2-005, Examination Category C-A, Items C1.10, C1.20, and C1.30, Pressure Retaining Welds in Pressure Vessels; Examination Category C-B, Items C2.21 and C2.22, Pressure Retaining Nozzle Welds in Vessels; and Examination Category C-C, Item C3.10, Integrally Welded Attachments on Vessels

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-A, Items C1.10, C1.20, and C1.30 require a 100% volumetric examination on Class 2 Vessel shell circumferential welds, head circumferential welds and tubesheet-to-shell welds.

Examination Category C-B, Item C2.21 requires both a 100% surface and volumetric examination on Class 2 nozzle-to-shell welds, and Item C2.22 requires a 100% volumetric examination on the vessel nozzle inside radius section.

Examination Category C-C, Item C3.10 requires a 100% surface examination on integrally welded attachments to Class 2 vessels.

Code Relief Request: Relief is requested from examining 100% of the Code-required volume on the 9 vessel shell circumferential welds (Item C1.10), 14 vessel head circumferential welds (Item C1.20), 9 vessel tubesheet-to-shell welds (Item C1.30), and 11 nozzle-to-shell welds (Item C2.21) listed in the Table attached to Request for Relief No. R2-005.

Relief is requested from the Code-required volumetric examination on the 3 nozzle inside radius sections (Item C2.22) listed in the Table submitted August 6, 1986 to be attached to Request for Relief No. R2-005.

Relief is also requested from examining 100% of the Code-required surface area on the 1 pressure vessel integrally welded attachment (Item C3.10) listed in the Table attached to Request for Relief No. R2-005

Reason for Relief: Weld configurations (end cap geometry, flanges, nozzles etc.) and obstructions (reinforcement plates, welded attachments, permanent hangers, insulation tabs, access ports, etc.) prevent examination of 100% of the Code-required surface area or volume on the 44 Class 2 vessel welds listed in the Table attached to Request for Relief No. R2-005. In addition, some nozzles on each steam generator (3 nozzles total) were designed without a nozzle inside radius section, therefore, the Code-required volumetric examination could not be performed.

The Applicant reported that the volumetric and surface examinations on the subject components were accomplished as a "best effort" attempt to cover as much of the Code-required area or volume as possible. The areas where a complete 100% examination could not be achieved were indicated and noted, along with the limitation, on the data sheets.

It is also reported that these welds all received the ASME Code Section III volumetric and surface examinations during fabrication, as well as hydrostatic tests at design temperatures and pressures.

Staff Evaluation: The staff has reviewed the information submitted in Request for Relief No. R2-005, including the attached Table which lists the weld for which relief is being requested, the weld configuration, the Code examination requirement, the type of examination for which relief is requested, and the approximate percentage of the Code-required examination that was completed. The staff notes that in all cases, except the Steam Generator nozzle inside radius sections, a significant percentage of the Code-required examination was completed. Attachment 2 of the August 6, 1986 submittal provided a description of the Steam Generator nozzle inside radius section and showed why the Code-required volumetric examination of the inside radius could not be performed.

Based on the above review, the staff has concluded that the Section III volumetric and surface examinations performed during fabrication and the hydrostatic tests, supplemented by the limited Section XI volumetric examination, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

O. Request for Relief No. R3-001, (Class 3 Snubbers), Examination Category F-C, Item F3.50, Component Standard Supports

Relief Request No. R3-001 has been deleted as the Manufacturer's records of functional tests of snubbers are being used for the preservice tests in accordance with Section XI of the ASME Code.

## IV. CONCLUSIONS

Based on the foregoing, pursuant to 10 CFR 50.55a(a)(3), the staff has determined that certain Section XI required preservice examinations are impractical. The Applicant has demonstrated that either (i) the proposed alternatives would provide an acceptable level of quality and safety or (ii) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

The staff technical evaluation has not identified any practical method by which the existing Shearon Harris Nuclear Power Plant, Unit 1 can meet all the specific preservice inspection requirements of Section XI of the ASME Code. Requiring compliance with all the exact Section XI required inspections would delay the startup of the plant in order to redesign a significant number of plant systems, obtain sufficient replacement components, install the new components, and repeat the preservice examination of these components. Examples of components that would require redesign to meet the specific preservice examination provisions are: the reactor pressure vessel, the boron injection tank, the regenerative heat exchangers, the steam generators, and a number of the piping and component support systems. Even after the redesign efforts, complete compliance with the preservice examination requirements probably could not be achieved. However, the as-built structural integrity of the existing primary pressure boundary has already been established by the construction code fabrication examinations.

Based on the staff review and evaluation, it is concluded that the public interest is not served by imposing certain provisions of Section XI of the ASME Code that have been determined to be impractical. Pursuant to 10 CFR 50.55a(a)(3), relief is allowed from these requirements which are impractical to implement.

# APPENDIX K

## CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS

EGG-HS-6990

# CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS
# SHEARON HARRIS NUCLEAR POWER PLANTS UNITS 1 AND 2
# (Phase I)

Docket No. [50-400]
[50-401]

Author
C. R. Shaber

Principal Technical Investigator
T. H. Stickley

Published
August 1985

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

Prepared for the
U.S. Nuclear Regulatory Commission
Under DOE Contract No. DE-AC07-76IDO 1570

FIN No. A6457

# ABSTRACT

The Nuclear Regulatory Commission (NRC) has requested that all nuclear plants, either operating or under construction, submit a response of compliancy with NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." EG&G Idaho, Inc., has contracted with the NRC to evaluate the responses of those plants presently under construction. This report contains EG&G's evaluation and recommendations for Shearon Harris Power Plants Units 1 and 2.

EXECUTIVE SUMMARY

Shearon Harris Nuclear Power Plant Units 1 and 2 have taken action and made commitments that will bring them into compliance with six guidelines of NUREG 0612. The one exception is insufficient information concerning Guideline 4 to permit adequate evaluation of Special Lifting Devices.

This report reviews the requirements, the action and commitments SHNPP has made to verify consistency. Guideline 4 is discussed in Section 2.3.4

CONTENTS

ABSTRACT .......... ii

EXECUTIVE SUMMARY .......... iii

1. INTRODUCTION .......... 1

1.1 Purpose of Review .......... 1

1.2 Generic Background .......... 1

1.3 Plant-Specific Background .......... 3

2. EVALUATION AND RECOMMENDATIONS .......... 4

2.1 Overview .......... 4

2.2 Heavy Load Overhead Handling Systems .......... 4

2.3 General Guidelines .......... 5

2.4 Interim Protection Measures .......... 18

3. CONCLUDING SUMMARY .......... 19

3.1 Applicable Load-Handling Systems .......... 19

3.2 Guideline Recommendations .......... 19

3.3 Interim Protection .......... 21

3.4 Summary .......... 21

4. REFERENCES .......... 22

TABLES

2.1 Nonexempt Heavy Load-Handling Systems .......... 6

2.2 Exempt Heavy Load-Handling Systems .......... 7

3.1 NUREG-0612 Compliance Matrix .......... 20

CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS
SHEARON HARRIS NUCLEAR POWER PLANTS UNITS 1 AND 2
(Phase I)

# 1. INTRODUCTION

## 1.1 Purpose of Review

This technical evaluation report documents the EG&G Idaho, Inc., review of general load-handling policy and procedures at Shearon Harris Nuclear Power Plants Units 1 and 2 (SHNPP). This evaluation was performed with the objective of assessing conformance to the general load-handling guidelines of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants" [1], Section 5.1.1.

## 1.2 Generic Background

Generic Technical Activity Task A-36 was established by the U.S. Nuclear Regulatory Commission (NRC) staff to systematically examine staff licensing criteria and the adequacy of measures in effect at operating nuclear power plants to assure the safe handling of heavy loads and to recommend necessary changes to these measures. This activity was initiated by a letter issued by the NRC staff on May 17, 1978 [2], to all power reactor applicants, requesting information concerning the control of heavy loads near spent fuel.

The results of Task A-36 were reported in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." The staff's conclusion from this evaluation was that existing measures to control the handling of heavy loads at operating plants, although providing protection from certain potential problems, do not adequately cover the major causes of load-handling accidents and should be upgraded.

In order to upgrade measures for the control of heavy loads, the staff developed a series of guidelines designed to achieve a two-phase objective using an accepted approach or protection philosophy. The first portion of the objective, achieved through a set of general guidelines identified in NUREG-0612, Article 5.1.1, is to ensure that all load-handling systems at nuclear power plants are designed and operated such that their probability of failure is uniformly small and appropriate for the critical tasks in which they are employed. The second portion of the staff's objective, achieved through guidelines identified in NUREG-0612, Articles 5.1.2 through 5.1.5, is to ensure that, for load-handling systems in areas where their failure might result in significant consequences, either (a) features are provided, in addition to those required for all load-handling systems, to ensure that the potential for a load drop is extremely small (e.g., a single-failure-proof crane) or (b) conservative evaluations of load-handling accidents indicate that the potential consequences of any load drop are acceptably small. Acceptability of accident consequences is quantified in NUREG-0612 into four accident analysis evaluation criteria.

The approach used to develop the staff guidelines for minimizing the potential for a load drop was based on defense in depth and is summarized as follows:

- Provide sufficient operator training, handling system design, load-handling instructions, and equipment inspection to assure reliable operation of the handling system

- Define safe load travel paths through procedures and operator training so that, to the extent practical, heavy loads are not carried over or near irradiated fuel or safe shutdown equipment

- Provide mechanical stops or electrical interlocks to prevent movement of heavy loads over irradiated fuel or in proximity to equipment associated with redundant shutdown paths.

Staff guidelines resulting from the foregoing are tabulated in Section 5 of NUREG-0612.

## 1.3 Plant-Specific Background

On December 22, 1980, the NRC issued a letter [3] to Carolina Power and Light Company, the applicant for SHNPP requesting that the applicant review provisions for handling and control of heavy loads at SHNPP, evaluate these provisions with respect to the guidelines of NUREG-0612, and provide certain additional information to be used for an independent determination of conformance to these guidelines. On June 26, 1981, September 23, 1981 and September 19, 1983, Carolina Power and Light Company provided the initial responses [4], [5], and [5a] to this request. An additional response [10] was transmitted March 28, 1985.

## 2. EVALUATION AND RECOMMENDATIONS

### 2.1 Overview

The following sections summarize Carolina Power and Light Company's review of heavy load handling at SHNPP accompanied by EG&G's evaluation, conclusions, and recommendations to the applicant for bringing the facilities more completely into compliance with the intent of NUREG-0612. Carolina Power and Light Company's review of the facilities does not differentiate between the two units so it is assumed that both units are of identical design. The applicant has indicated the weight of a heavy load for this facility (as defined in NUREG-0612, Article 1.2) as 1750 pounds.

### 2.2 Heavy Load Overhead Handling Systems

This section reviews the applicant's list of overhead handling systems which are subject to the criteria of NUREG-0612 and a review of the justification for excluding overhead handling systems from the above mentioned list.

#### 2.2.1 Scope

"Report the results of your review of plant arrangements to identify all overhead handling systems from which a load drop may result in damage to any system required for plant shutdown or decay heat removal (taking no credit for any interlocks, technical specifications, operating procedures, or detailed structural analysis) and justify the exclusion of any overhead handling system from your list by verifying that there is sufficient physical separation from any load-impact point and any safety-related component to permit a determination by inspection that no heavy load drop can result in damage to any system or component required for plant shutdown or decay heat removal."

A. Summary of Applicant's Statements

The applicant's review of overhead handling systems identified the cranes and hoists shown in Table 2.1 as those which handle heavy loads in the vicinity of irradiated fuel or safe shutdown equipment.

The applicant has also identified fourteen other cranes that have been excluded from satisfying the criteria of the general guidelines of NUREG-0612. These are identified in Table 2.2 and the basic reason to satisfy the exclusion is given.

B. EG&G Evaluation

The criteria given in the Scope, 2.2.1 above was used as the basis on which Shearon Harris segregated the overhead handling systems into the nonexempt and exempt categories. This permitted development of Tables 2.1 and 2.2. Both of the categories were justified in a satisfactory manner to qualify for the nonexempt or exempt status.

C. EG&G Conclusions and Recommendations

Based on the information provided, EG&G concludes that the applicant has included all applicable hoists and cranes in their list of handling systems which must comply with the requirements of the general guidelines of NUREG-0612.

## 2.3 General Guidelines

This section addresses the extent to which the applicable handling systems comply with the general guidelines of NUREG-0612, Article 5.1.1. EG&G's conclusions and recommendations are provided in summaries for each guideline.

TABLE 2.1. SHEARON HARRIS UNITS 1 AND 2 NONEXEMPT HEAVY LOAD-HANDLING SYSTEMS

| Building and Hoisting System | Rating |
|---|---|
| Containment | |
| Circular Bridge Crane | 250 Ton |
| Circular Bridge Auxiliary | 50 Ton |
| Jib Crane | 5 Ton |
| Manipulator Crane | Not in submittal |
| Fuel Handling | |
| FHB Bridge Crane | Not in submittal |
| FHB Cask Crane | 150 Ton |
| FHB Auxiliary Crane | 12 Ton |
| Diesel Generator | |
| Diesel Generator Bridge Crane | 4 Ton |
| Turbine | |
| Turbine Building Gantry Crane | 215 Ton |
| Turbine Building Gantry Auxiliary | 50 Ton |
| Reactor Auxiliary | |
| Item 2 Motorized Trolley[a] | 3 Ton |
| Item 3 Motorized Trolley[a] | 3 Ton |
| Item 6 Hand Geared Trolley | 3 Ton |
| Item 14 Motorized Trolley[a] | 3 Ton |

a. Subsequent information, see Section 2.3.7 below indicates that these 3 hoisting systems will qualify for exemption.

TABLE 2.2. SHEARON HARRIS UNITS 1 AND 2 EXEMPT HEAVY LOAD HANDLING SYSTEMS

| Identification | Capacity and Type | Comment on Basis for Exclusion |
|---|---|---|
| **Containment Building** | | |
| Miscellaneous Hoist Item 17 | 10 Ton Motorized Trolley | Load drop could not damage any system or component required for safe shutdown |
| Equipment Removal Crane | 50 Ton Main Crane | Operates outside of Containment Building and does not pass over any equipment required for safe shutdown or decay heat removal. |
| Equipment Removal Crane Auxiliary | 10 Ton Auxiliary | |
| **Waste Processing Building (contains no equipment for safe shutdown or waste heat removal)** | | |
| WPB Bridge Crane | 1 Ton Crane | Load drop exposes no equipment required for safe shutdown or decay heat removal. |
| Miscellaneous Item 1 | 10 Ton Hoist, Motorized Trolley | Extends into Rea. Aux. Bldg. does not approach Safety related equipment |
| Miscellaneous Item 7 | 2 Ton Hoist, Motorized Trolley | Items 1, 7, 8, 9, 10, and 15 are in the Waste Process Building which contains no equipment required for safe shutdown or decay heat removal. |
| Miscellaneous Item 8 | 7-1/2 Ton Hoist, Motorized Trolley | |
| Miscellaneous Item 9 | 1 Ton Hoist, Hand Geared Trolley | |
| Miscellaneous Item 10 | 1 Ton Hoist, Hand Geared Trolley | |
| Miscellaneous Item 15 | 1 Ton Hoist, Hand Geared Trolley | |
| **Reactor Auxiliary Building** | | |
| Miscellaneous Item 4 | 3 Ton Motorized Trolley | Load drop could not damage any equipment required for safe shutdown or decay heat removal. |
| **Fuel Handling Building** | | |
| Miscellaneous Item 5 | 2 Ton Hoist, Hand Geared Trolley | Load drop could not damage any equipment required for safe shutdown or decay heat removal. |
| **Turbine Building** | | |
| Miscellaneous Item 11 | 5 Ton Motorized Trolley | Load drop could not damage any equipment required for safe shutdown or decay heat removal. |
| Miscellaneous Item 12 | 5 Ton Motorized Trolley | |

The NRC has established seven general guidelines which must be met in order to provide the defense-in-depth approach for the handling of heavy loads. These guidelines consist of the following criteria from Section 5.1.1 of NUREG-0612:

- Guideline 1--Safe Load Paths
- Guideline 2--Load-Handling Procedures
- Guideline 3--Crane Operator Training
- Guideline 4--Special Lifting Devices
- Guideline 5--Lifting Devices (not specially designed)
- Guideline 6--Cranes (Inspection, Testing, and Maintenance)
- Guideline 7--Crane Design.

These seven guidelines should be satisfied for all overhead handling systems and programs in order to handle heavy loads in the vicinity of the reactor vessel, near spent fuel in the spent-fuel pool, or in other areas where a load drop may damage safe shutdown systems. The succeeding paragraphs address the guidelines individually.

2.3.1 Safe Load Paths [Guideline 1, NUREG-0612, Article 5.1.1(1)]

> "Safe load paths should be defined for the movement of heavy loads to minimize the potential for heavy loads, if dropped, to impact irradiated fuel in the reactor vessel and in the spent-fuel pool, or to impact safe shutdown equipment. The path should follow, to the extent practical, structural floor members, beams, etc., such that if the load is dropped, the structure is more likely to withstand the impact. These load paths should be defined in procedures, shown on equipment layout drawings, and clearly marked on the floor in the area where the load is to be handled. Deviations from defined load paths should require written alternative procedures approved by the plant safety review committee."

A. Summary of Applicant's Statements

Load paths follow the safest and shortest routes with consideration given to avoidance of fuel and safety related equipment. It will be necessary to handle heavy loads over portions of the reactor fueling cavity when no other safe alternative path is available.

Safe load path drawings are available on the operating floor for signalmen; heavy load flow charts are located in all applicable crane cabs; the signalman will be instructed to walk down the load path prior to each lift, or if this is not possible, review the load path with the crane operator prior to lifting or load movement.

The manager, Maintenance is delegated authority to approve an alternate load path, and load handling area. A heavy load that must be carried over the open reactor vessel, if not identified on current load path drawings, requires prior review by the plant Nuclear Safety Committee. Their approval is contingent upon the following:

1. Use lifting equipment (lifting apparatus and crane) with a rated capacity at least twice the load to be handled.

2. Use a four point or redundant lifting arrangement to preclude a load drop in the event of a single lift point failure.

Deviations from the specified load paths will be subsequently reviewed in accordance with plant procedures for changes to plant procedure.

B. EG&G Evaluation

The actions and methods established heavy load safe path control is consistent with Guideline 1.

C. EG&G Conclusions and Recommendations

SHNPP actions and commitments are consistent with Guideline 1.

2.3.2 Load-Handling Procedures [Guideline 2, NUREG-0612, Article 5.1.1(2)]

"Procedures should be developed to cover load-handling operations for heavy loads that are or could be handled over or in proximity to irradiated fuel or safe shutdown equipment. At a minimum, procedures should cover handling of those loads listed in Table 3-1 of NUREG-0612. These procedures should include: identification of required equipment; inspections and acceptance criteria required before movement of load; the steps and proper sequence to be followed in handling the load; defining the safe path; and other special precautions."

A. Summary of Applicant's Statements

A table attached to the SHNPP March 28, 1985 submittal [10] lists 63 heavy loads with assigned procedure control numbers. The procedures have been or will be written for each heavy load movement. SPRO-22, Plant Operating Manual, Volume 4 Part 1, "Maintenance Management Manual" in Section 5.0 Procedures in Subsection 5.1 provides 29 safe operating practices on heavy load handling. Other subsections of 5 and 6 cover all aspects of load handling details. These are provided as a part of the submittal.

B. EG&G Evaluation

The information submitted and commitments in the procedures cover all aspects of Guideline 2. Upon completion of all the procedures SHNPP will be consistent with the Guideline.

C. <u>EG&G Conclusions and Recommendations</u>

The SHNPP actions and commitments are consistent with Guideline 2.

2.3.3 <u>Crane Operator Training [Guideline 3, NUREG-0612, Article 5.1.1(3)]</u>

"Crane operators should be trained, qualified, and conduct themselves in accordance with Chapter 2-3 of ANSI B30.2-1976, 'Overhead and Gantry Cranes' [6]."

A. <u>Summary of Applicant's Statements</u>

Crane operators and signalmen will be trained, qualified, and instructed to conduct themselves in accordance with the requirements of ANSI B30.2-1976 with no exceptions. Plant maintenance procedure MMM 20 reflects the requirements of ANSI B30.2-1976 including the manner in which their crane operators and signalmen qualification records will be maintained.

B. <u>EG&G Evaluation</u>

The commitments are consistent with the requirements of Guideline 3. In addition, review of the MMM 20, Section 5.6 shows that it provides the details for; Physical Requirements, Training, Testing, Certification and Recertification. These manual guides confirm that SHNPP is proceeding toward satisfactory accomplishment.

C. <u>EG&G Conclusions and Recommendations</u>

The actions taken and commitments for operator training qualification and conduct indicate there is consistency with Guideline 3.

### 2.3.4 Special Lifting Devices [Guideline 4, NUREG-0612, Article 5.1.1(4)]

"Special lifting devices should satisfy the guidelines of ANSI N14.6-1978, 'Standard for Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or More for Nuclear Materials' [7]. This standard should apply to all special lifting devices which carry heavy loads in areas as defined above. For operating plants, certain inspections and load tests may be accepted in lieu of certain material requirements in the standard. In addition, the stress design factor stated in Section 3.2.1.1 of ANSI N14.6 should be based on the combined maximum static and dynamic loads that could be imparted on the handling device based on characteristics of the crane which will be used. This is in lieu of the guideline in Section 3.2.1.1 of ANSI N14.6 which bases the stress design factor on only the weight (static load) or the load and of the intervening components of the special handling device."

A. Summary of Applicant's Statements

Most of the lifting devices for use at SHNPP have either not been delivered or constructed yet. Thus the information required for a complete response is not available at this time. The information that is available shows:

- o Internals Lifting Rig is built and on site. It received a load test at 125% of load design capacity.
- o Spent Fuel Storage Rack Lifting Rig has been contracted for, but not yet designed. It is to be single failure proof, remotely operated and designed in conformance with latest codes and standards as of December 1980.

B. EG&G Evaluation

This guideline relates only to specially designed lifting devices. It calls for stress design factors meeting ANSI N14.6 using combined static and dynamic loads. These conditions are more than code requirements for static load only. Also, the intervening component loads must be considered.

C. EG&G Conclusions and Recommendations

(1) Consideration of the special requirements must be given the design of these and any other special lifting devices sufficiently in advance of need to assure that the devices controlled by this guideline are consistent with ANSI N14.6 and are designed for static and dynamic loads.

(2) When special lifting devices are used with single failure proof cranes and handles heavy loads over vital safety equipment the design of any other components (shackles, turnbuckles) should meet NUREG 0612 Article 5.1.6 requirements also.

(3) The information in 2.3.4 plus the EG&G Evaluations and Conclusions above should be followed during the continuing development of Special Lifting Devices to assure consistency with Guideline 4.

2.3.5 Lifting Devices (Not Specially Designed) [Guideline 5, NUREG-0612, Article 5.1.1(5)]

"Lifting devices that are not specially designed should be installed and used in accordance with the guidelines of ANSI B30.9-1971, 'Slings' [8]. However, in selecting the proper sling, the load used should be the sum of the static and maximum dynamic load. The rating identified on the sling should be in terms of the 'static load' which produces the maximum static and dynamic load. Where this restricts slings to use on only certain cranes, the slings should be clearly marked as to the cranes with which they may be used."

A. Summary of Applicant's Statements

All slings used in moving heavy loads will meet or exceed the requirements of ANSI B30.9-1971.

All slings utilized will have a minimum safety factor of 5. The rated load when selecting sling size will be the sum of the static and dynamic load or greater. The dynamic load being the greater of 15% of the static load or 5% for every foot/minute of hook speed.

The rating identified on the sling should be in terms of the static load which reduces the maximum static and dynamic load. Where this restricts the slings for use on only certain cranes, the slings shall be clearly marked as to the crane on which they may be used.

B. EG&G Evaluation

Actions specified and practices to be followed indicate that lifting devices not specially designed are consistent with Guideline 5.

C. EG&G Conclusions and Recommendations

The safe operating practices on selection and use of slings indicates SHNPP is consistent with Guideline 5.

2.3.6 Cranes (Inspection, Testing, and Maintenance) [Guideline 6, NUREG-0612, Article 5.1.1(6)]

"The crane should be inspected, tested, and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976, 'Overhead and Gantry Cranes,' with the exception that tests and inspections should be performed prior to use where it is not practical to meet the frequencies of ANSI B30.2 for periodic inspection and test, or where frequency of crane use is less than the specified inspection and test frequency (e.g., the polar crane inside a PWR containment may only be used every 12 to 18 months during refueling operations, and is generally not accessible during power operation. ANSI B30.2, however, calls for certain inspections to be performed daily or monthly. For such cranes having limited usage, the inspections, test, and maintenance should be performed prior to their use)."

A. Summary of Applicant's Statements

Cranes shall be inspected, tested and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976 "Overhead and Gantry Cranes" with the exception that test and inspection should be performed prior to use where it is not practical to meet the frequency of ANSI B30.2 for periodic inspections and tests or where frequency of crane use is less than specified test and inspection frequency.

In addition, maintenance procedures give details of frequent and periodic inspection for each type of crane, and testing requirements.

B. EG&G Evaluation

The actions specified and procedures to be followed generally are consistent with Guideline 6. The exception is consistent with acceptable procedure given in the NUREG "Synopsis of Issues Associated with NUREG 0612."

C. EG&G Conclusions and Recommendations

SHNPP is consistent with Guideline 6 for crane inspection, test and maintenance.

2.3.7 Crane Design [Guideline 7, NUREG-0612, Article 5.1.1(7)]

"The crane should be designed to meet the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976, 'Overhead and Gantry Cranes,' and of CMAA-70, 'Specifications for Electric Overhead Traveling Cranes' [9]. An alternative to a specification in ANSI B30.2 or CMAA-70 may be accepted in lieu of specific compliance if the intent of the specification is satisfied."

A. Summary of Applicant's Statements

At SHNPP the Circular Bridge Crane, Manipulator Crane, FHB Bridge Crane, FHB Cask Crane, and FHB Auxiliary Crane are part of the fuel handling system. These cranes are designed in conformance with Regulatory Guide 1.13 as detailed in Section 1.8 of the SHNPP FSAR. Codes and Standards adhered to, including CMAA Specification 70 and ANSI B30.2, are given in FSAR Section 9.1.4.2.8. Specific information in addition to the aboye general comment, is provided for individual cranes as follows:

Containment Building

- o Circular Bridge Crane--the Ebasco specification CAR-SH-AS-2 requires compliance with CMAA 70.

- o The Containment Building Circular Bridge Auxiliary crane is designed in accordance with CMAA-70 and ANSI B30.2-1976.

- o The Jib Crane--can be mounted on any one of six base plates. Design was to Ebasco specification CAR-SH-AS-5B which requires that all cranes trolleys and hoists included comply with Hoist Manufacturing Institute, CMAA Specification 74 (Under Running Single Girder Electric Overhead Traveling Cranes) the specification for Underhung Cranes of the Monorail Manufacturing Association and applicable parts of ANSI. Also the design calls for ability to withstand Safe Shutdown Earthquake Events.

- Manipulator Crane is described in the FSAR and in Westinghouse Specification 677055.

Fuel Handling Building

- FHB Bridge Crane is described in the FSAR and Westinghouse specification 676470

- FHB Cask Crane is described in the FSAR. Ebasco specification CAR-SH-AS-4 requires compliance with CMAA 70 and OSHA title 29 CFR which contains ANSI B30.2.

- FHB Auxiliary is described in the FSAR. Ebasco specification CAR SH AS 47 requires compliance with CMAA 70 and ANSI B30.2 and that the crane be single failure proof.

Diesel Generator Building

- D. G. Bridge Crane is designed to Ebasco specification CAR SH AS 58 which requires crane, trolley and hoist to comply with standards of the Hoist Manufacturing Institute, CMAA 74, the Specifications for Underhung Cranes of the Monorail Manufacturing Association, and parts of ANSI. Also, the specifications call for the crane to withstand a safe shutdown earthquake.

Turbine Building

- The Turbine gantry crane was built to Ebasco specification CAR SH AS 3 which complies with CMAA 70. Additionally, seismic and weather considerations are specified.

- The Turbine Building Gantry Crane, main and auxiliary, are designed in accordance with CMAA-70 and ANSI B30.2-1976.

Reactor Auxiliary Building

- Items 2, 3, 6, and 14 are 3 ton hoists and trolleys built to Ebasco specification CAR SH AS 14 requiring the trolley hoists to comply with standards of the Hoist Manufacturing Institute and applicable parts of ANSI. "Items 2, 3, and 14 will be used only when the component each one serves is taken out of service, thus posing no threat to safety-related equipment in the event of a load drop."

- The Auxiliary Building three ton hoist (Item 6) is designed in accordance with CMAA-70 and ANSI B30.16.

B. EG&G Evaluation

The applicant statements indicate that the lifting systems which handle heavy loads have been designed consistent with acceptable criteria for Guideline 7.

C. EG&G Conclusions and Recommendations

SHNPP crane design is consistent with NUREG 0612, Guideline 7.

## 2.4 Interim Protection Measures

The NRC staff has established (NUREG-0612, Article 5.3) six measures to be initiated to provide assurances for operating plants. Since SHNPP is still under construction, the interim protection measures do not apply.

## 3. CONCLUDING SUMMARY

### 3.1 Applicable Load-Handling Systems

The list of cranes and hoists supplied by the applicant as being subject to the provisions of NUREG-0612 apparently is complete (see Section 2.2.1).

### 3.2 Guideline Recommendations

Compliance with the seven NRC guidelines for heavy load handling (Section 2.3) are partially satisfied at SHNPP. This conclusion is represented in tabular form as Table 3.1. Consistency in compliance with the intent of these guidelines is summarized below:

| Guideline | Recommendation |
|---|---|
| 1. Section 2.3.1 Safe Load Paths | SHNPP actions and commitments are consistent with Guideline 1. |
| 2. Section 2.3.2 Load Handling Procedures | The SHNPP actions and commitments show consistence with Guideline 2. |
| 3. Section 2.3.3 Crane Operator Training | The actions taken and commitments for operator training, qualification and conduct, indicate the is consistencey with Guideline 3. |

TABLE 3.1. SHEARON HARRIS NUCLEAR POWER PLANTS UNIT 1 AND UNIT 2 NUREG-0612 COMPLIANCE MATRIX

| | | Guidelines | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
| Equipment Designation | Heavy Load Information | Safe Load Paths | Procedures | Crane Operator Training | Special Lifting Devices | Slings | Crane Inspection Test Maintenance | Crane Design |
| **Containment Building** | | | | | | | | |
| Circular Bridge Crane | 250 Ton | C | C | C | I | C | C | C |
| Circular Bridge Auxiliary | 50 Ton | C | C | C | I | C | C | C |
| Jib Crane | 5 Ton | C | C | C | I | C | C | C |
| Manipulator Crane | | C | C | C | I | C | C | C |
| **Fuel Handling Building** | | | | | | | | |
| Bridge Crane | | C | C | C | I | C | C | C |
| Cask Crane | 150 Ton | C | C | C | I | C | C | C |
| Auxiliary Crane | 12 Ton | C | C | C | I | C | C | C |
| **Diesel Generator Building** | | | | | | | | |
| DG Bridge Crane | 4 Ton | C | C | C | I | C | C | C |
| **Turbine Building** | | | | | | | | |
| TB Gantry Crane | 250 Ton | C | C | C | I | C | C | C |
| TB Gantry Auxiliary | 50 Ton | C | C | C | I | C | C | C |
| **Reactor Auxiliary Building** | | | | | | | | |
| Item 2 Motorized Trolley | 3 Ton | C | C | C | I | C | C | R |
| Item 3 Motorized Trolley | 3 Ton | C | C | C | I | C | C | R |
| Item 6 Hand Geard Trolley | 3 Ton | C | C | C | I | C | C | C |
| Item 14 Motorized Trolley | 3 Ton | C | C | C | I | C | C | R |

C = Applicant action or commitment is consistent with NUREG-0612 Guideline.
NC = Applicant action is not consistent with NUREG-0612 guideline.
R = Applicant proposes revision or modification that is consistent with intent of guideline.
I = Insufficient information provided by the applicant.

| Guideline | Recommendation |
|---|---|
| 4. Section 2.3.4 Special Lifting Devices | Only partial information is provided. Indicate the number of special lifting devices and for each, provide the information Guideline 4 requires. Special lifting devices components used with single failure proof cranes require special consideration given in NUREG 0612 Article 5.1.6. |
| 5. Section 2.3.5 Lifting Devices Not Specially Designed | The safe operating practices for selection and use of slings indicate that SHNPP is consistent with Guideline 5. |
| 6. Section 2.3.6 Crane Inspection, Testing and Maintenance | SHNPP is consistent with Guideline 6 for crane inspection, testing and maintenance. |
| 7. Section 2.3.7 Crane Design | SHNPP crane design is consistent with NUREG 0612, Guideline 7. |

## 3.3 Interim Protection

EG&G's evaluation of information provided by the applicant indicates that the following actions are necessary to ensure that the six NRC staff measures for interim protection at SHNPP are met:

| Interim Measure | Recommendation |
|---|---|

The SHNPP is under construction so interim protection measures are not applicable.

## 3.4 Summary

None.

## 4. REFERENCES


1. NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, NRC.

2. V. Stello, Jr. (NRC), Letter to all applicants. Subject: Request for Additional Information on Control of Heavy Loads Near Spent Fuel, NRC, 17 May 1978.

3. USNRC, Letter to Carolina Power and Light Company. Subject: NRC Request for Additional Information on Control of Heavy Loads Near Spent Fuel, NRC, 22 December 1980.

4. E. E. Utley, Executive V.P. Power Supply and Engineering and Construction, Carolina Power and Light Co. to Director Division of Licensing USNRC, Washington, DC 20555, June 26, 1981.

5. M. A. McDuffie Senior V.P. Engineering and Construction Carolina Power and Light Company, to Mr. Darrell G. Eisenhut Director Division of Licensing. USNRC, Washington, DC 20555, September 23, 1981.

5a. M. A. McDuffie Senior V.P. Nuclear Generation, Carolina Power and Light Company, to Harold R. Denton Director office of Nuclear Regulation USNRC Washington, DC 20555, September 19, 1983.

6. ANSI B30.2-1976, "Overhead and Gantry Cranes."

7. ANSI N14.6-1978, "Standard for Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or more for Nuclear Materials".

8. ANSI B30.9-1971, "Slings."

9. CMAA-70, "Specifications for Electric Overhead Traveling Cranes."

10. S. R. Zimmerman, Manager Nuclear Licensing, Carolina Power and Light Co., to Mr. Harold R. Denton, Director of Office of Nuclear Regulation, USNRC, Washington, DC, 20555, March 28, 1985.


23382

APPENDIX L

CONFORMANCE TO GENERIC LETTER 83-28, ITEM 2.1 (PART 1),
EQUIPMENT CLASSIFICATION (RTS COMPONENTS)

EGG-NTA-7226

# CONFORMANCE TO GENERIC LETTER 83-28
# ITEM 2.1 (PART 1) EQUIPMENT CLASSIFICATION (RTS COMPONENTS)

GINNA
HADDAM NECK
MILLSTONE 3
HARRIS 1

R. Haroldsen

Published July 1986

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

Prepared for the
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555
Under DOE Contract No. DE-AC07-76ID01570
FIN Nos. D6001 and D6002

## ABSTRACT

This EG&G Idaho, Inc. report provides a review of the submittals from selected operating and applicant pressurized Water Reactor (PWR) plants for conformance to Generic Letter 83-28, Item 2.1 (Part 1). The following plants are included in this review.

| Plant Name | Docket Number | TAC Number |
|---|---|---|
| Ginna | 50 244 | 52841 |
| Haddam Neck | 50 213 | 52843 |
| Millstone 3 | 50 423 | OL |
| Harris 1 | 50 400 | OL |

# 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 PWR Licensing-A, by the EG&G Idaho, Inc.

The U.S. Nuclear Regulatory Commission funded this work under the authorization B&R 10-19-19-11-3 and 20-19-40-41-3, FIN Nos. D6001 and D6002.

CONTENTS


ABSTRACT ........................................................ ii

FOREWORD ........................................................ iii

1. INTRODUCTION AND SUMMARY ..................................... 1

2. PLANT RESPONSE EVALUATIONS ................................... 3

2.1 Ginna ........................................................ 3

2.2 Conclusion ................................................... 3

2.3 Haddam Neck and Millstone 3 .................................. 5

2.4 Conclusion ................................................... 5

2.5 Harris Unit 1 ................................................ 6

2.6 Conclusion ................................................... 6

3. GENERIC REFERENCES ........................................... 7

## 1. INTRODUCTION AND SUMMARY

On February 25, 1983, both of the scram circuit breakers at Unit 1 of the Salem Nuclear Power Plant failed to open upon an automatic reactor trip signal from the reactor protection system. This incident was terminated manually by the operator about 30 seconds after the initiation of the automatic trip signal. The failure of the circuit breakers was determined to be related to the sticking of the undervoltage trip attachment. Prior to this incident, on February 22, 1983, an automatic trip signal was generated at Unit 1 of the Salem Nuclear Power Plant 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 of 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 Salem Unit 1 incidents are reported in NUREG-1000, "Generic Implications of the ATWS Events at the Salem Nuclear Power Plant."[1] As a result of this investigation, the Commission (NRC) requested (by Generic Letter 83-28, dated July 8, 1983)[2] all licensees of operating reactors, applicants for an operating license, and holders of construction permits to respond to generic issues raised by the analyses of these two ATWS events.

This report is an evaluation of the responses submitted from a group of similar pressurized water reactors for Item 2.1 (Part 1) of Generic Letter 83-28.

The results of the reviews of several plant responses are reported on in this document to enhance review efficiency. The specific plants reviewed in this report were selected based on the similarity of plant design and convenience of review. The actual documents which were reviewed

## 2. PLANT RESPONSE EVALUATIONS

### 2.1 R. E. Ginna Nuclear Power Plant, 50-244, TAC No. 52841

The licensee for the Ginna Nuclear Power Plant (Rochester Gas and Electric Corp) provided a response to Item 2.1 (Part 1) in a submittal dated November 4, 1983. The submittal states that the reactor trip system components were confirmed to be classified as safety-related. The controlling document for safety-related activities and the identification of safety-related structures, systems and components is through Appendix A of the Quality Assurance Manual. This document contains guidance concerning the designation of safety-related equipment. Administrative procedures were identified that are used to control safety-related activities.

The licensee has plans for an expanded computerized system for listing safety-related items and controlling the activities associated with the safety-related items. This system was to be completed by the end of 1984. However, a submittal from the licensee dated August 23, 1985 stated that the Computerized Maintenance Management System database and associated administrative procedures had not been completed. A new plan of action was to be developed by December 31, 1985. Information received by telephone on May 7, 1986 indicated that the Computerized Maintenance Management system had not been completed but is expected to be completed by the end of 1986.

### 2.2 Conclusion

Based on our review of the licensee's responses, we find that the licensee's description of the presently existing program for identifying, classifying and treating reactor trip system components as safety-related meet the requirement of Item 2.1 (Part 1) of the Generic Letter 83-28, and are therefore acceptable. The licensee's planned program for the Computerized Maintenance Management System is relevant to the wider scope of Item 2.2.1 which deals with the all safety-related components of the entire plant. The new system and its status will be considered in the forthcoming review of Item 2.2.1.

## References

1. Letter, J. E. Maier, Rochester Gas and Electric Corp, to D. M. Crutchfield, NRC, November 4, 1983.

2. Letter, R. W. Kober, Rochester Gas and Electric Corp., to D. M. Crutchfield, NRC, August 23, 1985.

### 2.3 Haddam Neck, 50-213, TAC No. 52843, Millstone 3, 50-423 (OL)

The licensee/applicant for Haddam Neck and Millstone Unit 3 (Northeast Nuclear Energy Co.) responded to the requirements of Item 2.1 (Part 1) in submittals dated November 8, 1983, May 9, 1985 and September 5, 1985. The submittals state that all components whose function is required to trip the reactor are identified as Category 1 (safety related) on their Material, Equipment and Parts List (MEPL) and that safety-related activities on these components including maintenance, work orders and parts replacement will be completed using Category 1 controls.

### 2.4 Conclusion

Based on the review of the licensee's/applicant's submittals, we find that the licensee's/applicant's responses confirm that the components necessary to perform reactor trip are classified as safety related and that all activities relating to these components are designated as safety related. These responses, therefore, meet the requirements of Item 2.1 (Part 1) of Generic Letter 83-28, and are acceptable.

References


1. Letter, W. G. Counsil, Northeast Nuclear Energy Co., to D. G. Eisehnut, NRC, November 8, 1983.

2. Letter, J. F. Opeka, Northeast Nuclear Energy Co., to J. A. Zuolinski NRC, May 9, 1985.

3. Letter, J. F. Opeka, Northeast Nuclear Energy Co., to B. J. Youngblood, NRC, September 5, 1985.

## 2.5 Shearon Harris Unit 1, 50-400 (OL)

The applicant for Shearon Harris Unit 1 (Carolina Power and Light Co.) responded to the requirements of Item 2.1 (Part 1) in submittals dated November 7, 1983 and May 31, 1985. The applicant stated in the first submittal that a Q-list identifying safety-related components was being developed along with implementing plant procedures. In addition plant procedures were being developed to ensure that components whose function is required to trip the reactor are identified as safety-related on relevant documents to control safety-related activities. The May 31, 1985 provided confirmation that the Q-list had been completed and the administrative controls implemented.

## 2.6 Conclusion

Based on the review of the licensee's submittals, we find that the applicant has verified that the components that are necessary to perform reactor trip are classified as safety-related and that activities relating to the safety-related components are controlled by procedures which reflect the special requirements for handling safety-related components. We, therefore find that the applicant's responses meet the requirements of Item 2.1 (Part 1) and are acceptable.

### References


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

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

## 3. GENERIC REFERENCES


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

2. 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.

APPENDIX M

# TECHNICAL EVALUATION REPORT OF THE DETAILED CONTROL ROOM DESIGN REVIEW FOR CAROLINA POWER AND LIGHT COMPANY SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1

# TECHNICAL EVALUATION REPORT

# OF THE

# DETAILED CONTROL ROOM DESIGN REVIEW

# FOR

# CAROLINA POWER AND LIGHT COMPANY

# SHEARON HARRIS NUCLEAR POWER PLANT

UNIT 1

July 25, 1986

JACK W. SAVAGE

GARY L. JOHNSON

Lawrence Livermore National Laboratory

for the

United States

Nuclear Regulatory Commission

TABLE OF CONTENTS


| | Page |
|---|---|
| 1. Background | 1 |
| 2. Discussion | 2 |
| 2.1 Establishment of a Qualified Multidisciplinary Review Team | 3 |
| 2.1.1 Requirement | 3 |
| 2.1.2 Findings | 3 |
| 2.1.3 Conclusions | 4 |
| 2.2 System Function and Task Analysis | 4 |
| 2.2.1 Requirement | 4 |
| 2.2.2 Findings | 4 |
| 2.2.3 Conclusions | 5 |
| 2.3 Comparison of Control and Display Requirements with a Control Room Inventory | 5 |
| 2.3.1 Requirement | 5 |
| 2.3.2 Findings | 5 |
| 2.3.3 Conclusions | 6 |
| 2.4 Control Room Survey | 6 |
| 2.4.1 Requirement | 6 |
| 2.4.2 Findings | 6 |
| 2.4.3 Conclusions | 9 |
| 2.5 Assessment of HEDs | 9 |
| 2.5.1 Requirement | 9 |
| 2.5.2 Findings | 9 |
| 2.5.3 Conclusions | 11 |
| 2.6 Selection of Design Improvements | 11 |
| 2.6.1 Requirement | 11 |
| 2.6.2 Findings | 11 |
| 2.6.3 Conclusions | 12 |
| 2.7 Verification of Control Room Design Improvements | 12 |
| 2.7.1 Requirement | 12 |
| 2.7.2 Findings | 12 |
| 2.7.3 Conclusions | 13 |
| 2.8 Coordination of Control Room Improvements with Other Programs | 13 |
| 2.8.1 Requirement | 13 |
| 2.8.2 Findings | 13 |
| 2.8.3 Conclusions | 14 |
| 3. Conclusions | 14 |
| 4. References | 16 |

## TECHNICAL EVALUATION REPORT OF THE DETAILED CONTROL ROOM DESIGN REVIEW FOR CAROLINA POWER AND LIGHT COMPANY SHEARON HARRIS NUCLEAR POWER PLANT UNIT 1

### 1. BACKGROUND

Licensees and applicants for operating licenses shall conduct a Detailed Control Room Design Review (DCRDR). The objective is to "improve the ability of nuclear power plant control room operators to prevent accidents or cope with accidents if they occur by improving the information provided to them" (NUREG-0660, Item I.D.1). The need to conduct a DCRDR was confirmed in NUREG-0737 and Supplement 1 to NUREG-0737. DCRDR requirements in Supplement 1 to NUREG-0737 replaced those in earlier documents. Supplement 1 to NUREG-0737 requires each applicant or licensee to conduct a DCRDR on a schedule negotiated with the Nuclear Regulatory Commission (NRC).

NUREG-0700 describes four phases of the DCRDR and provides applicants and licensees with guidelines for its conduct. The phases are:

1. Planning
2. Review
3. Assessment and implementation
4. Reporting

NUREG-0800, Section 18.1 provides additional guidance to be used in developing and evaluating DCRDR programs.

Supplement 1 to NUREG-0737 requires that the DCRDR include the following elements:

1. Establishment of a qualified multidisciplinary review team.
2. Function and task analyses to identify control room operator tasks and information and control requirements during emergency operations.
3. A comparison of display and control requirements with a control room inventory.
4. A control room survey to identify deviations from accepted human factors principles.
5. Assessment of human engineering discrepancies (HEDs) to determine which are significant and should be corrected.
6. Selection of design improvements.

7. Verification that selected design improvements will provide the necessary correction and do not introduce new HEDs.

8. Coordination of control room improvements with changes from other programs such as the safety parameter display system (SPDS), operator training, Reg. Guide 1.97 instrumentation, and upgraded emergency operating procedures (EOPs).

Licensees are expected to complete Element 1 during the DCRDR's planning phase, Elements 2 through 4 during the DCRDR's review phase, and Elements 5 through 7 during the DCRDR's assessment and implementation phase. Completion of Element 8 is expected to cut across the planning, review, and assessment and implementation phases.

A Summary Report is to be submitted at the end of the DCRDR. As a minimum it shall:

1. Outline proposed control room changes.

2. Outline proposed schedules for implementation.

3. Provide summary justification for HEDs with safety significance to be left uncorrected or partially corrected.

The NRC staff evaluates the organization, process, and results of the DCRDR. Results of the evaluation are documented in a Safety Evaluation Report (SER) published within two months after receipt of the Summary Report.

## 2. DISCUSSION

The evaluation in this report is based on the first two references and attachments below and the results of the meeting of December 20, 1985.

- Letter NLS-85-325 and attachments (Ref. 9)
- Letter NLS-86-127 and attachments (Ref. 10)
- Letter NLS-86-227 and attachments (Ref. 14)
- December 20, 1985 meeting in Bethesda, Maryland between representatives from CP&L, the NRC, and LLNL.

Letter NLS-86-127 (Ref. 10) contains a statement that

> "The attached material was reviewed and discussed with the NRC human factors reviewers during the March 18-19, 1986 on-site meeting and was determined to adequately address all NRC and LLNL concerns."

The results of those discussions are not considered in this report because LLNL was not represented at that meeting. We have considered only the printed attachments to NLS-86-127. Appropriate portions of other references listed in Section 4 of this report were also considered.

These aggregated responses to the NRC audits, reports and correspondence are intended by CP&L to adequately address the satisfaction of CRDR requirements. Note that the NRC acronym "DCRDR" and the CP&L acronym "CRDR" have the same meaning.

This evaluation considered the following:

- o A review and assessment of the CP&L methodologies, processes and conclusions conveyed by the text of the Revised Final Summary Report to meet the requirements of Supplement 1 to NUREG-0737.
- o An assessment of the step-by-step CRDR processes.
- o An assessment of the completeness of the CRDR review criteria.
- o An assessment of the systematic and comprehensive execution of the CRDR processes.

## 2.1 ESTABLISHMENT OF A QUALIFIED MULTIDISCIPLINARY REVIEW TEAM

### 2.1.1 Requirement

Supplement 1 to NUREG-0737 requires the establishment of a multidisciplinary review team. Guidelines for team selection are found in NUREG-0700.

### 2.1.2 Findings

CP&L established a multidisciplinary review team for the DCRDR of the Shearon Harris Nuclear Plant. The team consisted of CP&L and Essex Corporation personnel, representing a cross-section of the required disciplines. The team was supported by the Architect and Engineer (A&E) (Ebasco), the Nuclear Steam Supply System (NSSS) vendor (Westinghouse) and other qualified individuals, as appropriate. The qualifications of the review team members are contained in Appendix F of the CP&L Summary Report, and a description of the review team composition is stated in Section 2 of the Summary Report.

The review team was divided into the following three groups:

- o Human Factors Evaluation Group.
- o Human Factors/Operations Support Group.
- o Project Management/Nuclear Operations/Plant Engineering and Design Group.

Figure 2-1 of the CP&L report describes the structure of the CRDR completion/reassessment dedicated core team. Figure 2-2 of the CP&L report outlines the task responsibilities of team members and team leaders in the categories of primary and support responsibilities and approval authority. Section 2.2 of the CP&L Report describes the CP&L management support given to the review team.

Tasks have been assigned to team members with the appropriate expertise to effectively accomplish DCRDR tasks.

2.1.3 Conclusions

The CP&L RFSR confirms the conclusion stated in the On-Site Audit Report of 3-28-84 that the CP&L Review team has met the requirements of Supplement 1 to NUREG-0737 to establish a multidisciplinary review team to conduct a DCRDR.

2.2 SYSTEM FUNCTION AND TASK ANALYSIS

2.2.1 Requirement

Supplement 1 to NUREG-0737 requires the applicant to perform system function and task analyses to identify control room operator tasks and operator information and control requirements during emergency operations. Furthermore, Supplement 1 to NUREG-0737 recommends the use of function and task analyses that had been used as the basis for developing emergency operating procedures, technical guidelines, and plant-specific emergency operating procedures to define these requirements.

2.2.2 Findings

CP&L used the Westinghouse Owners Group (WOG) Emergency Response Guidelines (ERG), Revision 1, and the WOG High Pressure (HP) Basic System Review and Task Analysis (SRTA) as the basis for developing and performing the SHNPP Systems Function and Task Analysis (SFTA).

Figure 6-1 of Section 6.4 of the RFSR illustrates the CP&L process used as a basis for the following:

- o Construct, from the WOG generic ERG HP Basic System Review and Task Analysis (SRTA) Matrix and Element tables, a SHNPP plant-specific version of the SRTA Task/System Sequence Matrix tables and Element tables. (Figures 6-1 and 6-2 of the Revised Summary Report). Figure 6-2 to identify the tasks and subtasks associated with each ERG guideline. Figure 6-3 to identify the data needed to determine action and information requirements.

- o Combine the above items with the "background information" and "source documents" listed in Fig. 6-1 of the RFSR.

- o Create a set of SHNPP-1 Specific System Function Task Analysis Tables (Matrix Tables RFSR, Fig. 6-4, Element Tables RFSR, Fig. 6-5.).

- o Create an EOP/ERG "Transition Document" which consists of these sections:

  - A list of differences between the WOG ERG HP reference plant and SHNPP-1.

  - A set of deviation forms that explain the variances in tasks and task steps between SHNPP-1 ERG steps and WOG ERG steps.

- A list of parameter value deviations between the SHNPP-1 EOPs and the SHNPP-1 ERGs.

- o Create lists of plant-specific Action and Information Requirements Details (AIRD) (Fig. 6-7 of the RFSR).

- o Create from the AIRD a computerized data base Action Information Requirements Summary (AIRS) and use it for selecting and sorting to summarize information and action requirements across tasks and elements (Fig. 6-8a, 6-8b, of the RFSR).

The report states that this AIRS data base was used during the verification activities to:

- o assess the availability and suitability of instruments and equipment used by control room operators and

- o to assist in the selection of event sequences to be analyzed during the validation of control room functions.

The above discussion describes the CP&L methodology to identify the characteristics of information and control needs independently of what exists on the control board. It responds to the concerns expressed in the NRC on-site audit report of March 28, 1984, the draft TER of January 16, 1986, and other correspondence and communications.

### 2.2.3 Conclusions

The CP&L SFTA methodology and process satisfy the requirements of Supplement 1 to NUREG-0737 in this regard.

## 2.3 COMPARISON OF CONTROL AND DISPLAY REQUIREMENTS WITH A CONTROL ROOM INVENTORY

### 2.3.1 Requirement

Supplement 1 to NUREG-0737 requires the applicant to make a control room inventory and to compare the operator display and control requirements determined from the task analyses with the control room inventory to determine the availability and suitability of controls and displays used to satisfy operator information and control needs.

### 2.3.2 Findings

CP&L conducted a systematic inspection and review of the control room and relevant documentation to develop the control room inventory. Sections 6.1.3.4, 6.5. and 6.6 of the Summary Report discuss the inventory method. These sections also discuss how the availability and suitability of control room displays and controls was verified by comparison of the AIRS against the inventory and against actual control room hardware. The December 20, 1985 CP&L presentations at Bethesda included an example of an inventory data base printout.

2.3.3 Conclusions

CP&L has fulfilled the requirements of Supplement 1 to NUREG-0737 in this area.

## 2.4 CONTROL ROOM SURVEY

2.4.1 Requirement

Supplement 1 to NUREG-0737 requires that a control room survey be conducted to identify deviations from accepted human factors principles. NUREG-0700 provides guidelines and criteria for conducting a control room survey.

2.4.2 Findings

CP&L performed SHNPP-1 control room surveys in 1980 and 1981 using NUREG-CR-1580 guidelines (Section 3 of the RFSR). In June to December 1983 they surveyed 13 Back Panels (Summary Report Sections 1.2.5, 4) and the Auxiliary Control Panel (RFSR Sections 1.2.6, 5) using NUREG-0700 guidelines. During the above time period, the NRC issued various updated guidance and conducted an on-site In-Progress Audit in August, 1983. CP&L responded by reviewing their prior work, updating their CRDR plans, and initiated CRDR Completion/Reassessment activities in December, 1984 (RFSR Sections 1.2.7, 6,7). The surveys are complete except for 4 surveys that must wait for CR construction to be completed. These surveys will be conducted prior to fuel load. Due to the circumstances described above the CP&L methods and HF guidelines have been appropriately modified to meet current NRC requirements.

Correspondence during the above time between CP&L and the NRC is summarized in a reference list in Section 1.1.1 of the RFSR.

The CP&L Completion/Reassessment program was subdivided into the following tasks:

| Task | Summary Report Section |
|---|---|
| Operating Experience Review | 6.2 |
| Conduct Surveys | 6.3 |
| System Functions and Task Analysis | 6.4 |
| Control Room Inventory | 6.5 |
| Verification of Task Performance | 6.6 |
| Validation of Control Room Functions | 6.7 |
| SPDS Review | 6.3.3.10 |

These tasks are abstracted in Section 6.1.3 of the Summary Report, and detailed in the sections tabulated above.

The Completion/Reassessment control room surveys were planned to follow the guidance of NUREG-0700, Section 6.0.

The surveys that were performed are:

1. Workspace
2. Anthropometrics
3. Emergency Equipment
4. Maintainability
5. Annunciator System
6. Controls
7. Displays
8. Labels and Location Aids
9. Computer System
10. Conventions

The following surveys have not yet been conducted because of the unfinished status of the CR and are considered to be open items.

1. Ambient Noise
2. Illumination
3. HVAC
4. Communications

Each survey was directed by a task plan containing procedures covering the following areas, as appropriate:

1. Measurements
2. Observations
3. Questionnaires/Interviews
4. Document Reviews

Details of the task plan organization and procedures are described in Section 6.3.2 and Appendix E of the Summary Report.

The HEDs were identified by the intermingling of the seven survey task processes described in section 6.1.3, of the Summary Report.

The HEDs' identified are summarized in narrative form in the Summary Report Sections listed below, and in more detail in appendices A-1 through A-26 and Appendix B of the Summary Report.

| Subject | Summary Report Section |
|---|---|
| o HF Design Evaluation of SHNPP-1 (1980-81) | 3.2.4 |
| o Back Panels (1983) | 4.4 |
| o Auxiliary Control Panel (RSP) (1983) | 5.4 |
| o Operating Experience review | 6.2.2.4 |
| o Control Room Surveys | 6.3.3 |
| o Verification | 6.6.4 |
| o Validation | 6.7.3 |

The HEDs identified by CP&L fall into the following areas:

- CR generic HED types which exist in various combinations on several CR panels.
- HEDs resulting from individual surveys of specific CR panels/systems.
- HEDs resulting from specific CRDR activities (e.g., Operating Experience Review (OER) Verification, Validation, In-progress audit, Safety Parameter Display System (SPDS).

There are no HEDs specifically identified as having originated from the SFTA/Inventory comparison.

During the March 18-19 on-site meeting, NRC expressed concern about the review of panel AEP-1. CP&L submitted additional information via letter NLS-86-184 [15] which justifies not improving human engineering problems with this panel on the basis that misuse of the equipment on this panel would have no safety significance. Review of this discussion indicates that several of these devices are safety related, however, misuse of a single device would not by itself be a safety concern. The need to misuse more than one device forms a large part of CP&L's basis for not correcting AEP-1 problems. It is not clear, however, that misuse of controls for redundant devices on this panel would require two independent operator errors. Given the labeling problems and lack of demarcation, it appears that erroneously selecting a incorrect pair of devices is not significantly less likely than erroneous selection of a single device. Further, it appears that justification for not correcting problems with reactor vessel and pressurizer vent valve controls has not been provided.

### 2.4.3 Conclusions

CP&L has planned and executed a detailed and comprehensive CR survey which is complete except for the four areas yet to be finished. When CP&L completes and reports to the NRC the four remaining surveys and resolves NRC concerns with the AEP-1 panel, the control room survey requirements of Supplement 1 to NUREG-0737, will be met.

It is suggested that a future NRC site visit review the existing problems and CP&L's proposed corrective action regarding AEP-1.

## 2.5 ASSESSMENT OF HEDs

### 2.5.1 Requirement

Supplement 1 to NUREG-0737 requires that HEDs be assessed to determine which HEDs are significant and should be corrected. NUREG-0700 contains guidelines for the assessment process.

Section 2.5 and Exhibit 2.2 of Appendix A to SRP Section 18.1 contain additional assessment guidance. The objective of the assessment process is to identify HEDs that can individually or interactively impact plant safety, operator physical performance, sensory/perceptual performance, and/or cognitive performance. Examples of significant task variables are communications needs, task duration and frequency, delay or absence of feedback, accuracy and speed requirements, and concurrent task requirements.

### 2.5.2 Findings

The present Completion/Reassessment program differs from the originally original CP&L policy to fix all HEDs during the redesign process so as to end up with an "HED-free" design. The original CP&L policy was to correct every HED by designing it out of the system, with the objective of achieving an HED-free board. The execution of this philosophy obviated the necessity to follow the NUREG-0700 recommendations of formally assessing each HED for importance, potential safety consequences, the cumulative impact of minor HEDs, determination of priorities, setting implementation schedules, etc. The In-Progress Audit Team Report of March 28, 1984, and Section 18.5.1 of Supplement 1 to the SER for SHNPP-1 concluded that the original policy was acceptable.

The modified policy states, in Section 7.2 and 7.3 of the RFSR, that the HED Assessment Team (HEDAT) assessed all HEDs, evaluated their relative significance, and placed each HED in a category determined by safety consequences, violation of technical specifications, and potential for degradation of operator performance and/or operator error. Following assessment, the HEDs were reviewed and decisions made concerning the extent to which corrective actions would be selected and implemented, and partially or noncorrected HEDs justified.

Section 7.3.1 of the RFSR describes the following factors considered in the assessment of probability of error:

- o Component design factors (e.g., deviations from the guidelines, conformance with plant convention).

- o Component use task factors (e.g., difficulty, frequency, time demands).

- o Human factors (e.g., physical performance, sensory and perceptual performance).

There is no mention that an assessment of cumulative and interactive effects of HEDs was made.

Section 7.3.2 of the RFSR describes the following criteria used in the assessment of consequences of error on plant safety:

- o Potential impact considering the system/functions affected by the error.

- o Errors that could lead to the unavailability of safety-related systems/ functions.

- o Violation of a technical specification or unsafe operation.

The current paraphrased categories assigned are described in RFSR Section 7.3.3.

| Category | Comment |
|---|---|
| I | High probability of error and high consequence of error, or low probability of error and high consequence of error. |
| II | High probability of error and low consequence of error. |
| III | Low probability of error and low consequence of error. |
| IV | Nonsignificant probability of error with no impact on operator performance |

Figure 7.4 of the RFSR charts paths used to determine the HED categories. HEDs were appropriately recategorized if found to create new HEDs or to invalidate other corrected HEDs. HEDs collected in Categories I, II, and III were analyzed and identified for disposition as follows:

- o Correct by enhancement

- o Correct by design improvement alternatives

### 2.5.3 Conclusions

With the exception of the assessment of cumulative and interactive effects of HEDs, CP&L's process and methodology for assessment of HEDs is acceptable and meets the requirement of Supplement 1 to NUREG-0737 for this DCRDR task. CP&L needs to formally submit to NRC a discussion of the method used to evaluate cumulative and interactive effects of HEDs in order to allow an unqualified conclusion in this area.

## 2.6 SELECTION OF DESIGN IMPROVEMENTS

### 2.6.1 Requirement

Supplement 1 to NUREG-0737 requires selection of control room design improvements that will correct significant HEDs. It also states that improvements that can be accomplished with an enhancement program should be done promptly.

### 2.6.2 Findings

As stated in the NRC in-progress audit report, alternate design improvements for each HED were considered during the CP&L redesign review process executed during the redesign of the Harris MCB. NUREG-1580 criteria, along with the Essex developed Human Engineering Requirements Specifications (HERS) were used to support the review team choice of resolutions for each HED. The conduct of the redesign effort was similar to the determination of a new design.

It was also stated that part of the redesign effort included ongoing discussions with operators to verify that the MCB redesign details and HED corrective actions were compatible with operational needs, and left no discrepancies uncorrected. This included verification that any equipment found missing was, or would be, installed before the redesign was considered complete. The originally stated policy of correcting all HEDs during the execution of the redesign process prior to operation obviated the necessity of selecting an implementing schedule.

The NRC audit team concluded that the applicant would satisfy requirements of Supplement 1 to NUREG-0737 if the SHNPP DCRDR Summary Report completely documents the methodology and results of design improvement selection so that the NRC can confirm that the requirements have been satisfied.

The staff concluded in Section 18.5.2 of Supplement 1 to Safety Evaluation Report for SHNPP-1 that the original process for selection of design improvements was acceptable.

The selection process described in Sections 7.4, 7.5 and Fig. 7.5 of the RFSR is a modification of the original process, and includes consideration of the following criteria, regardless of HED priority ranking:

- o The extent of the proposed correction in terms of cost restrictions.
- o Safety consequences.
- o Analyses for correction by enhancement/design alternatives.

- o Determination that the HED would be corrected without invalidating other HED corrections or creating new HEDs.
- o Integration with other Supplement 1 to NUREG-0737 programs.
- o Other constraints (e.g. availability of equipment).

Figures 7-1, 7-5, 7-6, and 7-7 contain all the elements needed for assessment and selection. Sections 7.1.1 and 7.1.2 describe the methods used for recording and tracking HEDs. Figure 7-3 explains the HED numbering scheme, Sec. 7.4.2 describes detailed tracking of changes of FCR/DCN.

Corrective actions for HEDs were stated in Sec. 7.4.1 to be scheduled for implementation prior to fuel load with one exception (e.g., carpeting). Figure 7-1 and Fig. 7-5 of the RFSR depict the HED generation, review, design improvement, corrective action process.

The results of the CP&L assessment and selection of design improvement process were reviewed by LLNL. This review identified several HEDs for which the Summary Report did not provide enough information to allow a conclusion that adequate corrective action was planned. NRC reviewed these specific items during the March 1986 site visit and found CP&L's planned action to be acceptable in all cases.

2.6.3 Conclusions

CP&L's approach for selecting design improvements as described in the SHNPP-1 Revised Final Summary Report meets the requirements of Supplement 1 to NUREG-0737.

2.7 VERIFICATION OF CONTROL ROOM DESIGN IMPROVEMENTS

2.7.1 Requirement

Supplement 1 to NUREG-0737 requires verification that selected control room design improvements will provide the necessary corrections of HEDs and will not introduce new HEDs into the control room.

2.7.2 Findings

The In-progress Audit Report stated that the execution of the CP&L MCB redesign process to design HEDs out of the system incorporates HED assessment, the consideration of alternate designs in the selection and implementation of design improvements, and the use of the mock-up to study and confirm MCB rearrangements. As explained to the NRC audit team, it is inherent in this process that HED corrective actions will be verified to provide the necessary corrections of HEDs without introducing new HEDs. This process was acceptable to the staff.

Section 6-6 of the RFSR describes the objectives of the CP&L task performance capabilities verification task. Section 7.5 of the RFSR states that in determining the backfit for each HED the HEDAT verified that no new HEDs were created, other corrections were not invalidated, and that the correction is in compliance with

NUREG-0700 guidelines. Section 6.7 of the RFSR describes the CP&L validation/verification process. Section 6.7 is an extension of the SFTA and emphasizes the determination of the adequacy of the control room design to support operator task sequences and to verify that the improved control room does not contain uncorrected HEDs. CP&L calls this section "Validation".

Validation activities were based on the following as described in Sec. 6.7 of the RFSR:

- o Walk-throughs/talk-throughs performed with control room personnel and trained observers, including HEDAT members as follows:
  - Event sequences simulated in the control room and using RFSR Sec. 6.7.2.1 EOP events 1 through 14.
  - Table top exercises using updated control panel drawings, CR layout drawing, and appropriate Emergency Plant Procedures (EPPs) and Functional Restoration Procedures (FRPs) using RFSR Sec. 6.7.2.1 EOP events 15 through 26.
- o RFSR Sec. 6.7.2.2 states that the EOPs used to direct all operator actions during walk/talk-throughs included all EPPs and all FRPs needed to exercise the emergency related instruments and controls.

Section 6.7.2.3 describes in more detail the participant briefing and execution processes performed during the event scenarios, and the characteristics and attributes to be observed and recorded. Subsequent analytical results were recorded in HED reports as summarized in Sec. 6.7.3 of the RFSR and in Appendix A-26.

### 2.7.3 Conclusions

CP&L has installed an acceptable methodology and process to ensure that this requirement of Supplement 1 to NUREG-0737 is satisfied.

## 2.8 COORDINATION OF CONTROL ROOM IMPROVEMENTS WITH OTHER PROGRAMS

### 2.8.1 Requirement

Supplement 1 to NUREG-0737 requires that control room improvements be coordinated with changes from other programs; (e.g., safety parameter display system (SPDS), operator training, Regulatory Guide 1.97 (R.G. 1.97), and emergency operating procedures (EOPs)).

### 2.8.2 Findings

The Lead Discipline Engineer (LDE) served as coordinator between the CRDR and NUREG-0737 activities. Section 1.3 of the Summary Report states that CP&L recognizes the interface between the CRDR and the other programs, and that the CRDR organization includes consideration of the need for coordination with other activities to implement NUREG-0737 activities to satisfy NUREG-0737 requirements.

The Revised Final Summary Report briefly describes what is included in the integration (coordination) of the CRDR human factors effort with the SPDS, Reg. guide 1.97, EOPs, operator training, and the ERF. Block diagrams of the ERFIS/SPDS (Fig. 1-1) and the EOP (Fig. 1-2) efforts illustrate factor relationships. Attachment 1-2 is a summary of design standards and criteria for the TSC. Attachment 1-1 is a compilation of RG-1.97 implementation.

The Summary Report does not include detailed statements concerning how the systematic and comprehensive conduct of integration actions among the various initiatives was accomplished. Neither is a comprehensive system described whereby the LDE was formally consulted and/or advised by others concerning matters which should be coordinated.

The NRC in-progress audit report of March 28, 1984, stated that the intent of the coordination process was adequately recognized and planned.

2.8.3 Conclusions

In order to meet the requirements of Supplement 1 to NUREG-0737, the NRC should be satisfied that an auditable and comprehensive coordination effort was executed to meet the requirements of Supplement 1 to NUREG-0737. CP&L should explain to the NRC how it was ensured that:

- o the LDE and other personnel identified and responded to coordination topics.
- o systematic, effective and comprehensive interchanges of concerns and information occurred.
- o suitable responses were initiated to resolve coordination concerns, problems and interfaces.
- o suitable documents were generated to record, schedule, follow and implement responses to coordination efforts.

## 3. CONCLUSIONS

Carolina Power and Light Company's Detailed Control Room Design Review for the Shearon Harris Nuclear Power Plant, Unit 1 has, with three exceptions, fulfilled all DCRDR requirements of Supplement 1 to NUREG-0737. The three exceptions are:

- o The process for assessing cumulative and interactive effects of HEDs has not been described in sufficient detail to allow a final conclusion about the adequacy of the overall assessment process. CP&L should submit, for NRC review, a discussion of the process for assessing cumulative and interactive effects.
- o The details of CP&L's execution of the process for coordinating NUREG-0737 control room activities have not been described in sufficient detail to allow a final conclusion about the adequacy of their coordination effort. CP&L should submit for NRC review the needed information described in Sec. 2.8.3 of this report.

- NRC concerns about the AEP-1 panel are unresolved. It is recommended that NRC visit the Shearon Harris site to examine in more detail apparent HEDs associated with the AEP-1 panel and review CP&L's planned corrective actions for this panel once these have been fully defined.

JYBJAK:860601:7/25/86 -15-

## 4. REFERENCES


1. Human Factors Design Evaluation Report for Shearon Harris Unit 1 Control Room, January 23, 1981, revised September 16, 1981, and April 14, 1983.

2. Supplement 1 to NUREG-0737, "Requirements for Emergency Response Capability" (Generic Letter No. 82-33), December 17, 1982.

3. NUREG-0700, "Guidelines for Control Room Design Reviews," September 1981.

4. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Section 18.1 Appendix A, "Evaluation Criteria for Detailed Control Room Design Reviews," September 1984.

5. CP&L letter LAP-83-156 to H. R. Denton, supplemental information to the DCRDR Summary Report entitled, "Human Factors Design Evaluation Report for the Shearon Harris Unit 1," June 1, 1983.

6. CP&L letter LAP-83-426 to H. R. Denton, information requested by the NRC audit team, September 27, 1983.

7. NUREG-1580, "Human Engineering Guide to Control Room Evaluation," July 1980.

8. "Meeting Summary—Task Analysis Requirements of Supplement 1 to NUREG-0737—March 29, 1984, Meeting with Westinghouse Owners Group Procedures Subcommittee and Other Interested Persons," memorandum from H. Brent Clayton to Dennis L. Ziemann, April 5, 1984.

9. CP&L letter NLS-85-325 to H. R. Denton, "Response to SER Supplement No. 1, open item No. 14, Subpart I.D.1 Control Room Design Review" with 3 enclosures including the CRDR Final Summary Report, September 13, 1985.

10. CP&L letter NLS-86-127 of April 28, 1986, to H. R. Denton, transmitting revisions (replacement sections) to the SHNPP CRDR Final Summary Report, Ref. 9 above (Enclosure 1) and additional information applicable to Appendix A of the report (Enclosure 2).

11. "Human Factors Engineering Detailed Control Room In-Progress Audit Report, Shearon Harris Nuclear Power Plant," March 28, 1984.

12. NRC Letter to E. E. Utley, "Issuance of Supplement No. 1 to Safety Evaluation Report for Shearon Harris Nuclear Power Plant, Unit 1," July 9, 1984, to which were attached Pages 18-1 through 18-7 of Shearon Harris SSER 1.

13. Draft "Technical Evaluation Report of the Detailed Control Room Design Review for Carolina Power and Light Company, Shearon Harris Nuclear Power Plant," January 16, 1986.

14. CP&L letter NLS-86-227 to H. R. Denton, "transmitting revision 2 to the SHNPP CRDR Final Summary Report," June 30, 1986.

15. CP&L letter NLS-86-184 to H. R. Denton, "Control Room Design Review—Additional Information," May 30, 1986.

# APPENDIX N

## ERRATA

| SSER 3 Page | Line | Change |
|---|---|---|
| 9-4 | 8 | Change "2000 ppm to "7000 ppm" |
| 9-4 | 10 | Change "the normal charging path that employs" to "either the normal charging path or the safety injection path that employs" |
| 9-4 | 13 | Delete "train in the normal" |
| 9-4 | 19 | Change "normal charging path from the boric acid tank" to "above charging paths from the refueling water storage tank" |
| 9-4 | 21 | Change "boric acid from the boric acid tank" to "boric acid from the boric acid tank and the refueling water storage tank" |
| 9-7 | 8 | Change "reactor vessel" to "reactor coolant system" |
| 9-7 | 16 | Change "as described in item (a) above" to "as described in item (a) above and the refueling water storage tank will also be aligned to provide RCS makeup to ensure adequate makeup capability" |
| 9-7 | 20 | Change "bubbles" to "voids" |
| 9-7 | 5 | Change "feed the two steam generators" to "feed two of the three steam generators" |
| 9-8 | 7 | Change "sufficient tp keep" to "sufficient to keep" |
| 9-8 | 23 | Change tag no. "PI 0484.2" to "0.485.2" |
| 9-9 | 3 | Change "operator" to "operators" |
| 9-9 | 31 | Change "boron" to "boric acid" |
| 9-9 | 33 | Change "$T_{AV} \le 350°F$" to "$T_{av} = 350°F$" |
| 9-10 | 5-6 | Change "During" to "Prior to" |

| SSER 3 Page | Line | Change |
|---|---|---|
| 9-10 | 6 | Change "and boron transfer" to "and boric acid transfer" |
| 9-10 | 8-9 | Change "in order to prevent a return to criticality, if this has not been done earlier" to "in order to ensure adequate shutdown margin" |
| 9-12 | 17 | Change "and 3-hour" to "and 1- and 3-hour" |



*U.S.GOVERNMENT PRINTING OFFICE:1986-181-683:40012

NRC FORM 335
(2-84)
NRCM 1102,
3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

# BIBLIOGRAPHIC DATA SHEET

SEE INSTRUCTIONS ON THE REVERSE.

1. REPORT NUMBER *(Assigned by TIDC, add Vol. No., if any)*

NUREG-1038
Supplement No. 4

2. TITLE AND SUBTITLE

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

3. LEAVE BLANK

4. DATE REPORT COMPLETED

| MONTH | YEAR |
|---|---|
| October | 1986 |

5. AUTHOR(S)

6. DATE REPORT ISSUED

| MONTH | YEAR |
|---|---|
| October | 1986 |

7. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS *(Include Zip Code)*

Division of PWR Licensing-A
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

8. PROJECT/TASK/WORK UNIT NUMBER

9. FIN OR GRANT NUMBER

10. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS *(Include Zip Code)*

Same as 7. above

11a. TYPE OF REPORT

Technical

b. PERIOD COVERED *(Inclusive dates)*

12. SUPPLEMENTARY NOTES

13. ABSTRACT *(200 words or less)*

Supplement No. 4 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. 3 was issued, and (2) matters that the staff had under review when Supplement No. 3 was issued.

14. DOCUMENT ANALYSIS – a. KEYWORDS/DESCRIPTORS

b. IDENTIFIERS/OPEN-ENDED TERMS

15. AVAILABILITY STATEMENT

Unlimited

16. SECURITY CLASSIFICATION

*(This page)*
Unclassified

*(This report)*
Unclassified

17. NUMBER OF PAGES

18. PRICE

431-02-0403
Box 10

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

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

FIRST CLASS MAIL
POSTAGE & FEES PAID
USNRC
WASH. D.C.
PERMIT No. G-67