NUREG-0954
Supplement No. 5

Safety Evaluation Report
related to the operation of Catawba Nuclear Station, Units 1 and 2

Docket Nos. 50-413 and 50-414

Duke Power Company, et al.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

February 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-0954
Supplement No. 5

Safety Evaluation Report
related to the operation of Catawba Nuclear Station, Units 1 and 2

Docket Nos. 50-413 and 50-414

Duke Power Company, et al.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

February 1986

ABSTRACT

This report supplements the Safety Evaluation Report (NUREG-0954) issued in February 1983 by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission with respect to the application filed by Duke Power Company, North Carolina Muncipal Power Agency Number 1, North Carolina Membership Corporation, Saluda River Electric Cooperative, Inc., and Piedmont Municipal Power Agency, as applicants and owners, for licenses to operate the Catawba Nuclear Station, Units 1 and 2 (Docket Nos. 50-413 and 50-414, respectively). The facility is located in York County, South Carolina, approximately 9.6 km (6 mi) north of Rock Hill and adjacent to Lake Wylie. This supplement provides additional information supporting the license for initial criticality and power ascension to full-power operation for Unit 2.

CONTENTS

CONTENTS (Continued)

CONTENTS (Continued)

CONTENTS (Continued)

APPENDICES

TABLES

ABBREVIATIONS

ADV	atmospheric dump valve
ALAB	Atomic Licensing Appeal Board
ASLAB	Atomic Safety Licensing Appeal Board
ASLB	Atomic Safety Licensing Board
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
BMEP	break mean effective pressure
BNL	Brookhaven National Laboratory
BOP	balance of plant
BTP	Branch Technical Position
CDI	cumulative damage index
CDR	Construction Deficiency Report
CET	core exit thermocouple
CFR	Code of Federal Regulations
CHR	containment heat removal
CLA	cold-leg accumulator
CRT	cathode ray tube
DCRDR	detailed control room design review
DEMA	Diesel Engine Manufacturers Association
DR	design review
ECC	emergency core cooling
ECCS	emergency core cooling system
EDG	emergency diesel generator
EDO	Executive Director for Operations
EMO	electric motor operator
EPRI	Electric Power Research Institute
EPZ	emergency planning zone
ERG	emergency response guideline
FaAA	Failure Analysis Associates, Inc.
FEMA	Federal Emergency Management Agency
FSAR	Final Safety Analysis Report
GDC	General Design Criteri(on)(a)
HMS	hydrogen mitigation system
ICCI	inadequate core cooling instrumentation
IDCOR	Industry Degraded Core Rulemaking Program
IST	inservice testing

LANL	Los Alamos National Laboratory
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
LP	liquid penetrant
LTOP	low temperature overpressure protection
MAAP	Modular Accident Analysis Program
M/S	maintenance/surveillance
MSIV	main steam isolation valve
MT	magnetic particle testing
NB	boron recycle system
NC	reactor coolant system
NCIR	Non-Confirmatory Item Report
ND	residual heat removal system
NM	nuclear sampling system
NRC	U.S. Nuclear Regulatory Commission
NSSS	nuclear steam supply system
NTS	Nevada Test Site
NV	chemical and volume control system
OAC	operator aid computer
OL	operating license
PID	Partial Initial Decision
P&ID	piping and instrumentation diagram
PNL	Pacific Northwest Laboratory
PORC	Plant Operations Review Committee
PORV	power-operated relief valve
PT	penetrant testing
PVORT	Pump and Valve Operability Review Team
QA	quality assurance
QC	quality control
QR	quality revalidation
RCS	reactor coolant system
RG	Regulatory Guide
RHR	residual heat removal
RMS	root mean square
RTD	resistance temperature detector
RVLIS	reactor vessel level instrumentation system
SER	safety evaluation report
SIM	service information memorandum
SMM	subcooling margin monitor
SOE	sequence of events
SPDS	safety parameter display system
SQRT	Seismic Qualification Review Team
SRO	senior reactor operator
SRP	Standard Review Plan
SSER	supplement to the Safety Evaluation Report
SSF	standby shutdown facility
SSS	safe shutdown system

STA	shift technical advisor
SWEC	Stone & Webster Co.
TDI	Transamerica Delaval, Inc.
TER	technical evaluation report
TMI	Three Mile Island
UHI	upperhead injection
VCT	volume control tank
V&V	verification and validation
WOG	Westinghouse Owners Group

1 INTRODUCTION AND DISCUSSION

1.1 Introduction

On February 10, 1983, the Nuclear Regulatory Commission staff (NRC staff or staff) issued a Safety Evaluation Report (NUREG-0954) regarding the application by Duke Power Company, North Carolina Municipal Power Agency Number 1, North Carolina Electric Membership Corporation, Saluda River Electric Cooperative, Inc., and Piedmont Municipal Power Agency (collectively referred to as the licensee or Duke) for licenses to operate the Catawba Nuclear Station, Units 1 and 2. Since that time, four supplements to the Safety Evaluation Report (SER) have been issued (SSER 1, April 1983; SSER 2, June 1984; SSER 3, July 1984; and SSER 4, December 1984). This report is Supplement 5 to that SER. On January 17, 1985, a full-power license was issued for Unit 1.

This fifth SER supplement provides additional information supporting the issuance of an operating license for fuel loading, initial criticality, and power ascension up to full-power operation for the Catawba Nuclear Station, Unit 2. Each of the following sections of this supplement is numbered the same as the section 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.

Appendix A continues the chronology of the staff's principal actions related to the review of the application. Appendix B lists references used during the course of the review.* Appendix D is a list of principal contributors to this report. Appendices I and J, added to the SER by this supplement, contain memoranda from the Federal Emergency Management Agency (FEMA) concerning the licensee's March 18, 1985, submittal in response to the Atomic Safety and Licensing Board's Partial Initial Decision of September 18, 1984. Appendices K and L added to the SER by this supplement, contain reports prepared for the NRC by EG&G Idaho Inc. Appendix M contains a memorandum from FEMA dated October 8, 1985.

The Project Manager is Dr. Kahtan N. Jabbour. Dr. Jabbour may be contacted by calling (301) 492-7367 or by writing to the following address:

Dr. Kahtan N. Jabbour
Division of PWR Licensing-A
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

1.7 Summary of Outstanding Issues

SER Section 1.7 identified 18 outstanding issues that had not been resolved at the time the SER was issued. This fifth supplement updates the status of those

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

items. The current status of each of the 18 original issues is tabulated below, and the relevant sections of the SER and its supplements are indicated.

Issue	Status	Section(s)
(1) Conformance with SECY 82-352 with regard to quality assurance in design and construction of nuclear projects	Resolved (SSER 3)	1.1
(2) Performance of the SNSW pond using NUREG-0693	Resolved (SSER 2)	2.4.4.2
(3) Inservice pump and valve testing program	Changed to License Condition 35 (SSER 2)	3.9.6
(4) Seismic and environmental qualification of equipment		
(a) Seismic qualification	Changed to License Condition 38 (SSER 2)	3.10
(b) Environmental qualification	Changed to License Condition 39 (SSER 3)	3.11
(5) Thermal design procedures and flow measurements techniques	Resolved (SSER 2)	4.4.3.3
(6) Instrumentation for inadequate core cooling detection (II.F.2)	Changed to License Condition 5 (SSER 2)	4.4.3.4
(7) Pressurizer safety valve sizing and low-temperature overpressure protection	Resolved (SSER 2)	5.2.2.1, 5.2.2.2
(8) Model D steam generator preheater degradation		
(a) For Catawba Unit 1	Resolved (SSER 2)	5.4.2.3
(b) For Catawba Unit 2	Resolved (SSER 5)	5.4.2.3
(9) Conformance to the staff's position on design requirements of the RHRS and steam generator tube rupture	Changed to License Conditions 36 and 37 (SSER 2, SSER 3)	5.4.4, 15.4.4
(10) Lockout of manual control by the load sequencer and ECCS override and reset	Resolved (SSER 2)	6.3.2, 7.3.2.11
(11) Remote shutdown instrumentation and controls	Resolved (SSER 1)	7.4.2.2

Issue	Status	Section(s)
(12) Loss of both RHR trains resulting from a single instrument bus failure	Resolved (SSER 2)	7.4.2.4
(13) Power lockout to motor-operated valves	Resolved (SSER 2)	7.6.2.6, 8.4.4
(14) Fire protection program	Changed to License Condition 40 (SSER 3)	9.5.1
(15) Diesel generators emergency lighting, air intake and exhaust, and inadvertent operation of fire protection system in diesel generator buildings	Resolved (SSER 2)	9.5.3, 9.5.4.1, 9.5.8
(16) Emergency planning and related meteorology	Changed to Confirmatory Issue 42 (SSER 2)	2.3.3, 13.3
(17) Alarm in control room for boron dilution modes in all modes of operation	Changed to License Condition 41 (SSER 3)	15.2.4.2
(18) Control room design review	Changed to License Condition 33 (SSER 2)	18

1.8 Confirmatory Issues

SER Section 1.8 identified 41 confirmatory issues for which additional information and documentation were required to confirm preliminary conclusions. Supplement 2 added an additional confirmatory issue. This fifth supplement updates the status of those items for which the confirmatory information has subsequently been provided by the licensee and for which review has been completed by the staff. The current status of each of the original issues is tabulated below, and the relevant sections of the SER supplements are indicated.

Issue	Status	Section
(1) Probable maximum precipitation and its effects on safety-related structures and components	Resolved (SSER 2)	2.4.3.2
(2) Sediment accumulation in SNSW pond intake structures	Resolved (SSER 1)	2.4.4.2
(3) Postulated failure of CCW piping and its effects on permanent dewatering system and adjacent buildings	Resolved (SSER 1)	2.4.5
(4) Amplified seismic design spectra for NSW pipelines and diesel fuel oil tanks	Resolved (SSER 1)	2.5.2.3

Issue	Status	Section
(5) Dynamic stability of the SNSW pond dam under extreme loading conditions	Resolved (SSER 1)	2.5.4
(6) SSI for buildings not founded on rock	Resolved (SSER 2)	3.7.3
(7) Structural integrity of safety-related masonry walls	Resolved (SSER 1)	3.8
(8) Vertical seismic response spectra	Resolved (SSER 1)	3.9.2
(9) Loose-parts monitoring systems	Resolved (SSER 2)	4.4.3.1
(10) Listing of ASME Code Cases used in the construction of Section III, Class 1 components within the RCPB	Resolved (SSER 2)	5.2.1.2
(11) Preservice inspection program	Resolved (SSER 2)	5.2.4, 6.6
(12) Main steamline break using a revised heat transfer model	Changed to License Conditions 39 and 46 (SSER 3, SSER 4)	3.11, 6.2.1.1
(13) Subcompartment analysis	Resolved (SSER 2)	6.2.1.2
(14) Minimum containment pressure analysis	Resolved (SSER 2)	6.2.1.3
(15) Design provisions for containment isolation systems	Resolved (SSER 2)	6.2.4
(16) Containment purge system	Resolved (SSER 3, SSER 4)	6.2.4
(17) Justification for not testing certain isolation valves	Resolved (SSER 3)	6.2.6
(18) Fracture prevention of containment pressure boundary	Resolved (SSER 3)	6.2.7
(19) Compatibility of ECCS valve interlocks	Resolved (SSER 2)	6.3.2
(20) Postaccident environmental conditions and their impact on the ability of the operator to complete certain actions outside the control room	Resolved (SSER 2)	6.3.2

Issue	Status	Section
(21) Procedure for resetting ECCS after SIS (ECCS override and reset)	Resolved (SSER 2)	6.3.2
(22) NPSH analysis	Resolved (SSER 2)	6.3.4
(23) Inside-containment insulation and containment sump test	Resolved (SSER 2)	6.3.4
(24) LOCA sensitivity analysis	Resolved (SSER 2)	6.3.5.1
(25) Steam generator level control and protection	Resolved (SSER 2)	7.3.2.1
(26) Compliance with IE Bulletin 80-06	Resolved (SSER 2)	7.3.2.2
(27) Test of engineered safeguards P-4 interlock	Resolved (SSER 2)	7.3.2.7
(28) Containment pressure control system	Resolved (SSER 2)	7.3.2.10
(29) Remote shutdown instrumentation and controls	Resolved (SSER 1, SSER 4)	7.4.2.2, 14
(30) Control switches for RHR miniflow valves	Resolved (SSER 2)	7.4.2.5
(31) Instrumentation used to initiate safety functions	Resolved (SSER 2)	7.5.2.5
(32) Interlocks for reactor coolant system pressure control during low temperature operation	Resolved (SSER 1)	7.6.2.1
(33) Upper head injection manual control	Resolved (SSER 2)	7.6.2.3
(34) Key-locked switches used to override isolation of control room area HVAC system	Resolved (SSER 2)	7.6.2.4
(35) Separation of field run cables	Resolved (SSER 2)	8.4.5
(36) Flooding of electrical equipment as a result of a LOCA	Resolved (SSER 2)	8.4.7
(37) Load sequencer accelerated sequence	Resolved (SSER 2)	8.4.8
(38) 100% load reduction capability	Changed to License Condition 42 (SSER 3)	8.4.10 (SSER 2)
(39) Improved thermal design method	Deleted (SSER 2)	15.1

Issue	Status	Section
(40) Locked rotor accident	Resolved (SSER 2)	15.3.4
(41) ESF grade containment purge filter system design	Resolved (SSER 2, SSER 4)	15.4.6
(42) Emergency planning and related meteorology		
(a) Emergency preparedness	Resolved (SSER 5)	13.3
(b) Meteorology related to emergency planning	Resolved (SSER 4)	2.3.3

1.9 License Conditions

SER Section 1.9 identified 33 issues for which license conditions may be desirable to ensure that staff requirements are met during plant operation. Supplements 2 and 3 added 5 and 4 more license conditions, respectively, and 6 additional license conditions were added by Supplement 4. The license condition may be in the form of a condition in the body of the operating licenses, or a requirement in the Technical Specifications appended to the licenses. The license conditions are tabulated below, and the relevant sections of the SER and its supplements are indicated.

Issue	Status	Section
(1) Turbine system maintenance program	Unchanged (SER)	3.5.1.3
(2) Shift technical advisor (I.A.1.1)	Resolved (SSER 2)	13.5.1.3
(3) Relief and safety valve testing (II.D.1)	Resolved (SSER 2)	3.9.3.2
(4) Control and shutdown rods surveillance requirements	Resolved (SSER 2)	4.2
(5) Instrumentation for inadequate core cooling detection (II.F.2)		
(a) Unit 1	Unchanged (SSER 2)	4.4.3.4
(b) Unit 2	Resolved (SSER 5)	4.4.3.4
(6) Inservice inspection program	Unchanged (SSER 2)	5.2.4, 6.6
(7) Installation of reactor coolant vents (II.B.1)	Resolved (SSER 3)	5.4.5
(8) Accident monitoring instrumentation (II.F.1)	Resolved (SER)	11.5
(9) Containment isolation dependability (II.E.4.2)	Resolved (SER)	6.2.4

Issue	Status	Section
(10) Hydrogen control measures	Deleted for Unit 2 (SSER 5)	6.2.5
(11) ECCS flow measurements and NPSH verification	Resolved (SSER 3)	6.3.4.1
(12) Charging pumps deadheading	Resolved (SSER 2)	6.3.2
(13) Effect of nonseismic piping on safety injection pumps' miniflow lines	Resolved (SSER 2)	6.3.1
(14) PORV isolation system (II.K.3.1, II.K.3.2)	Resolved (SSER 2)	7.6.2.6, 15.5.3
(15) Low-temperature overpressure protection/power supplies for pressurizer relief valves and level indicators (II.G.1)	Resolved (SER)	8.4.12
(16) Compliance with NUREG-0612	Resolved (SSER 4)	9.1.5
(17) Postaccident sampling system (II.B.3)	Resolved (SSER 3)	9.3.2.2
(18) Internal corrosion protection for fuel oil storage tanks	Resolved (SSER 5)	9.5.4.2(3)
(19) Secondary water chemistry monitoring and control program	Resolved (SSER 2)	10.3.4
(20) Loss of primary source of condensate storage water	Resolved (SSER 2)	10.4.9
(21) Primary coolant outside containment (III.D.1.1)	Resolved (SER)	11.6
(22) Independent safety engineering group (I.B.1.2)	Technical Specifications 6.2.3.1, 6.2.3.2, 6.2.3.3, 6.2.3.4	None
(23) Emergency preparedness	Resolved (SSER 5)	13.3
(24) Control room access (I.C.4)	Resolved (SSER 2)	13.5.1.3
(25) NSSS vendor review of low-power testing and power ascension procedures (I.C.7)	Resolved (SSER 3)	13.5.3
(26) Pilot monitoring of selected emergency procedures for near-term operating license applicants (I.C.8)	Deleted (SSER 2)	13.5.2

Issue	Status	Section
(27) Implementation and maintenance of physical security plan	Unchanged (SSER 5)	13.6
(28) Report on outages of emergency core cooling system (II.K.3.17)	Resolved (SSER 4)	13.5.4
(29) Effect of high-pressure injection for small-break LOCA with no auxiliary feedwater (II.K.2.13)	Resolved (SSER 2)	15.5.1
(30) Voiding in the reactor coolant system (II.K.2.17)	Resolved (SSER 2)	15.5.2
(31) Anticipatory reactor trip (II.K.3.10)	Unchanged (SER)	5.2.2
(32) Revised small-break LOCA analysis (II.K.3.30, II.K.3.31)	Resolved (SSER 2)	15.5.6
(33) Control room design review (I.D.1)	Partially resolved (SSER 5)	18.2
(34) Short-term accident analysis and procedures revision (I.C.1)	Resolved (SSER 4)	13.5.2
(35) Inservice pump and valve testing program		
(a) Unit 1	Updated (SSER 4)	3.9.6
(b) Unit 2	Resolved (SSER 5)	3.9.6
(36) Design requirements of RHRS		
(a) Unit 1	Unchanged (SSER 2)	5.4.4
(b) Unit 2	Resolved (SSER 5)	5.4.4
(37) Steam generator tube rupture analysis	Unchanged (SSER 2, SSER 3, SSER 4)	15.4.4
(38) Seismic qualification of equipment	Resolved (SSER 5)	3.10
(39) Environmental qualification of equipment	Resolved (SSER 5)	3.11
(40) Fire Protection Program	Partially resolved (SSER 4, SSER 5)	9.5.1
(41) Alarm in control room for boron dilution in all modes of operation	Resolved (SSER 4)	15.2.4.2

Issue	Status	Section
(42) 100% of load reduction capability	Resolved (SSER 4)	8.4.10
(43) TDI diesel generator reliability		
(a) Unit 1	Added (SSER 4)	8.3.1
(b) Unit 2	Added (SSER 5)	8.3.1
(44) Shift crew composition	Resolved (SSER 5)	13.1.2.3
(45) Salem ATWS event actions (Generic Letter 83-28)	Unchanged (SSER 5)	15.6
(46) Main steam line break using a revised heat transfer model	Under review (SSER 5)	6.2.1.1
(47) Compliance with Regulatory Guide 1.97		
(a) Unit 1	Added (SSER 4)	7.5.2
(b) Unit 2	Added (SSER 5)	7.5.2
(48) Modifications to harassment procedures	Resolved (SSER 4)	17
(49) Main Steam Line Break Outside Containment	Added (SSER 5)	3.11
(50) Safety Parameter Display System	Added (SSER 5)	18.3

1.11 Nuclear Waste Policy Act of 1982

Section 302(b) of the Nuclear Waste Policy Act of 1982 states that NRC shall not issue or renew a license for a nuclear power reactor unless the utility has signed a contract with the Department of Energy for disposal services. Duke Power Company signed a contractual agreement with the Department of Energy on June 30, 1983.

2 SITE CHARACTERISTICS

2.3 Meteorology

2.3.3 Onsite Meteorological Measurements Program

The need for a fog-monitoring program to be conducted during operation of the Catawba Nuclear Station is discussed in Section 5.14.3 (Atmospheric Monitoring) of the Final Environmental Statement (July 1983). An operational fog-monitoring program, including schedule for implementation, is described in Section 4.2.3 of the Environmental Protection Plan (Nonradiological), included as Appendix B to the facility operating license.

In correspondence on this matter, the licensee proposed a revised (delayed) schedule for implementing the fog-monitoring program. Principal factors cited by the licensee in support of delayed implementation were "delays in reaching criticality and significant power on Unit 1" (see the January 31, 1985, letter from the licensee and recognition that the most "severe fogging events are not expected until fall" (see the May 1, 1985, letter, from the licensee). Fog has been monitored on a limited basis since September 1984, although the licensee considered data collected through the winter of 1984-1985 insufficient "to be useful for the interim report" (from the January 31, 1985, letter).

The staff agrees with the licensee that full thermal loading and seasonal preferences for fogging are important factors in determining the frequency of plant-induced fog. Because of these factors, the delay in implementing the fog-monitoring program from the schedule provided in the Environmental Protection Plan, i.e., "beginning with the startup and continued operation of Unit 1," is not considered significant. In the licensee's December 5, 1985, letter, the licensee confirmed full operation of the fog-monitoring program as of September 1, 1985, and indicated that the program would conclude "one year after startup and continued operation of Unit 2" as specified in the Environmental Protection Plan.

Also in the December 5, 1985, letter, the licensee fully described the components and extent of the operational fog-monitoring program to satisfy the provisions of the Environmental Protection Plan. The program described by the licensee should provide a reasonable data base to determine the frequency and intensity of fog induced by plant operation. Thus, the staff finds it acceptable.

3 DESIGN CRITERIA--STRUCTURE, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.6 Protection Against Dynamic Effects Associated With Postulated Rupture of Piping

3.6.2 Determination of Rupture Locations and Dynamic Effects Associated With the Postulated Rupture of Piping

General Design Criterion (GDC) 4 (of Appendix A to 10 CFR 50) requires that structures, systems, and components important to safety shall be designed to be compatible with and to accommodate the effects of the environmental conditions as a result of normal operations, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be adequately protected against dynamic effects that may result from equipment failures and from events and conditions outside the nuclear power plant. By NRC letter dated April 23, 1985, the licensee was granted an exemption from a portion of the requirements of GDC 4 for Catawba Unit 2. This exemption eliminates the need to (1) postulate pipe breaks in the reactor coolant system primary loop, (2) install primary loop pipe whip restraints, and (3) consider associated dynamic effects and loading conditions.

3.9 Mechanical Systems and Components

3.9.2 Dynamic Testing and Analysis of Systems, Components, and Equipment

On two recent separate occasions, system overpressurizations occurred at Catawba Unit 2. On April 19, 1985, the residual heat removal (ND)* system, with a design pressure of 600 psig, was pressurized to 2000 psig for about 3 hours. On the next day, the volume control tank (VCT), designed for 75 psig, was inadvertently pressurized to 700 psig. With no means to relieve the pressure, the VCT ruptured. Construction Deficiency Reports (CDRs) 414/85-08 (April 19 event) and 414/85-06 (April 20 event) were filed. The licensee later reported corrective actions taken (letters to the NRC Region II Administrator dated July 15 and July 24, 1985).

These two events are discussed below

(1) ND System Overpressurization (CDR 414/85-08)

During preparation for cold hydrostatic testing, a mini hydro of the reactor coolant (NC)* system was conducted with pressure up to 2000 psig. Two isolation valves at the hydro boundary were left open inadvertently. This allowed the NC pressure to enter the ND system via a temporary test line. The relief path from ND relief valve to the recycle holding tanks had been closed previously to support the Unit 1 operation. As a result, portions of the ND system, the boron recycle (NB)* system, and the nuclear sampling (NM)* system were overpressurized

*FSAR designation.

to 2000 psig for about 3 hours before the test was interrupted. After discovering the overpressurization, the licensee immediately took the following corrective actions.

- Reviewed the NC hydro boundary valves and the Unit 1/Unit 2 boundary valves.
- Installed a temporary relief header which would permit the ND relief valves to discharge into the Unit 2 turbine building sump.
- Formed a special communication channel to interface related groups for the remainder of the cold hydrostatic testing.
- Instructed operating personnel to use appropriate operating management procedures.
- Originated a Non-Confirmatory Item Report (NCIR) to identify and evaluate areas of overpressurized portions of the ND, NB, and NM systems.
- Performed analyses which identified portions of the systems that needed to be corrected before restart. In addition, these analyses provide a basis for the acceptance of the remainder of the overpressurized portions of the systems.
- Repaired 9 damaged valves and replaced 12 flanges and 1 valve as identified by analyses.

Overpressurized components are accepted if analyses demonstrated that they were not stressed beyond the elastic limit. For piping, this is done by performing a three-step calculation of the maximum permitted hydro pressure. Step 1 is to determine this pressure permitted by Duke Power Specification CNC-1232.00-00-0010 in the form of $(1.5)(1.06)\ P_a$, where P_a is the system design pressure. Step 2 is to determine this pressure by using the minimum yield strength as the maximum allowable stress in the piping. Step 3 is to determine this pressure by using the actual yield strength of the piping material in this piping as the maximum allowable stress. Piping is accepted as adequate if any one of the three values obtained exceeds the maximum pressure which occurs in the system. For piping flanges, however, only steps 1 and 3 are performed. Results from those calculations show that except for the 150-lb A182 F034 flanges for 12 relief valves, which were permanently deformed and needed to be replaced, all piping, flanges, bolting, and other components are adequate for the intended plant operation. Damaged flanges were replaced.

(2) <u>VCT Overpressurization (CDR 414/85-06)</u>

As part of the chemical and volume control (NV) system, the VCT is used to accept letdown and as a suction source for the charging pumps in the filling and venting of the NC system. Before the incident, a valve leakage of the NC pump seal return flow caused the VCT level to drop. The refueling water storage tank was swapped alternately with the VCT to bring the VCT level back up. During this process, the VCT was allowed to overfill, causing the flow to cease from the letdown orifice, and putting it under the NC pressure of 700 psig. Since the VCT relief path is through a Unit 1/Unit 2 boundary into a common relief header to the recycle holdup tanks, this path was locked up so there would be no interference with the Unit 1 operation. As a result, the VCT had no relief protection, and ruptured.

The following corrective actions were taken by the licensee:

- Identified and evaluated areas in the NV system affected by the overpressurization. This included piping, components, and instruments.

- Identified electric cables that may have been water damaged.

- Evaluated damage to hangers and the 6-inch liquid waste drain line.

- Realigned the NV system by reinstalling valve 2NV172A in its correct position and repairing header to a barrel sump on the 543-ft elevation.

- Installed a replacement VCT.

- Performed analyses which identified portions of the systems that need to be corrected before restart. In addition, these analyses provide a basis for the acceptance of the remainder of the overpressurized portions of the systems.

- Replaced the damaged NV system piping and VCT instrumentation tubing.

- Used the refueling water storage tank as the surge tank for the remainder of the cold hydrostatic tests.

- Reviewed instrument loops and isolated relief paths caused by Unit 1/ Unit 2 separation.

The stress calculations performed for the overpressurized NV system used a similar approach to the one described for the ND system. Results of the analyses indicated that the piping, threaded connections, and flanges did not suffer permanent damage from the 700-psig overpressurization, and therefore should be adequate for intended plant operations.

Conclusion

The licensee has identified and evaluated the permanently damaged components in the Catawba Unit 2 ND, NB, NM, and NV systems overpressurization incidents. They were either replaced or repaired. In addition, temporary relief protections were provided and working procedures were improved. The staff has concluded that analyses performed by the licensee indicate that most piping and components in those systems were provided with sufficient safety margins that the incidents did not impair their serviceability. The staff finds that corrective actions are acceptable.

3.9.6 Inservice Testing of Pumps and Valves

By letter dated October 25, 1985, the licensee submitted an Inservice Testing (IST) Program for pumps and valves for Catawba Nuclear Station, Unit 2. The licensee has stated that the IST Program will meet the requirements of 10 CFR 50.55a(g), including the 1980 Edition of the ASME Boiler and Pressure Vessel Code, Section XI, through the Winter 1981 Addenda. The licensee has requested relief from these Code requirements pursuant to 10 CFR 50.55a(g)(1) for certain pump and valve tests.

The proposed program of inservice testing (IST) of pumps and valves incorporates systems identified in the following list.

- reactor coolant
- chemical and volume control
- boron recycle
- containment air return exchange and hydrogen skimmer
- containment hydrogen sample and purge
- residual heat removal
- safety injection
- containment spray
- liquid radwaste
- containment valve injection water
- spent fuel cooling
- refueling water
- nuclear sampling
- component cooling
- nuclear service water
- containment purge system
- control area chilled water
- steam generator blowdown
- containment air release and addition
- feedwater
- auxiliary feedwater
- fire protection
- makeup demineralized water
- instrument air
- station air
- breathing air
- diesel generator engine cooling water
- diesel generator engine fuel oil
- diesel generator engine starting air

The proposed program satisfies the staff criteria for systems required to be incorporated into the IST program. The staff has completed a preliminary review of the Catawba Unit 2 IST program. This preliminary review indicated that it is impractical within the limitations of design, geometry, and accessibility for the licensee to meet certain specific requirements of the ASME Code. Relief from those requirements will not endanger life or property or the common defense and security of the public and is in the public interest, giving due consideration to the burden on the licensee that could result if the requirements were imposed. On the basis of experience at similar plants at which 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. If this relief were not granted, the licensee might be forced to curtail the operation of the plant, which constitutes a considerable burden. Therefore, pursuant to 10 CFR 50.55a(g)(6)(i), the relief that the licensee has requested from certain of the pump and valve testing requirements of the 1980 Edition of ASME Code Section XI through Winter 1981 Addenda should be granted for a period not to exceed 2 years from the date of issue of the operating license or until a detailed review of the justifications for each relief request has been completed, whichever comes first. If the review results in additional testing requirements, the licensee will be required to comply with them.

3.10 Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment

3.10.1 Seismic and Dynamic Loads

In response to a license condition requiring test verification of similarity of the seismic behavior of reactor protection system cabinets as installed at the plant with the conditions under which they were qualified by its vendor (Westinghouse Electric Corporation), the licensee, in its letter dated June 24, 1985, indicated the findings of its test program.

The reactor protection system cabinets were installed in the plant with an electrical isolation system which consisted of "Glastic sheets" at the mounting location of the cabinets to its foundation on the building floor. The seismic qualification tests performed by Westinghouse used cabinets that were directly mounted on the floor through anchors without any Glastic sheets. The staff was concerned that the intervening Glastic material could cause shifting of natural frequency of the cabinet, and thereby alter the seismic loading to the electric devices. In order to demonstrate that the seismic behavior of the cabinets as installed has not changed to a point as to challenge the original basis for its qualification, the licensee committed to conduct a seismic test program that would include simulation of the mounts used in its qualification tests, mounts as installed in the plant, and an alternative mount.

The seismic testing was performed for the licensee by Wyle Laboratory at its Huntsville, Alabama, facility. The cabinet used was modified, and additional masses (dummy weights) were added to simulate the Westinghouse solid-state protection system cabinet. Triaxial and random multifrequency tests were conducted for the mounting conditions indicated in the previous paragraph. The licensee stated that, on the basis of test results, response spectra at the location of electric devices of interest for all three mounting conditions were acceptable for operability of those devices, and that the seismic response of the cabinets was not significantly different between the three mounting conditions. The licensee has concluded that the cabinets as installed at the plant are adequate in terms of their seismic capability.

The staff reviewed the test report and notes that the test was conducted in such a manner that the adequacy of the seismic response of both the cabinet itself and the devices located within the cabinet could be observed. The staff concurs with the test summary that the intervening Glastic material as used in the field did not result in significant differences of natural frequency of the cabinet from that of the cabinet used in the test. The staff finds this acceptable and concludes that the licensee has satisfactorily met the requirements of this license condition. This issue is closed.

3.10.3 Seismic and Dynamic Qualification Program for Catawba Unit 2

Introduction

Evaluation of the licensee'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 Standard Review Plan (SRP) Section 3.10, and its ancillary documents, Regulatory Guides (RGs) 1.61, 1.89, 1.92, and 1.100; NUREG-0484; and Institute of Electrical and Electronics Engineers (IEEE) Standards 344-1975 and 323-1974. These documents define acceptable methodologies for the seismic qualification of equipment. Conformance to these criteria satisfies the appropriate 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, and is, therefore, acceptable.

Discussion

Evaluation of the program at Catawba Unit 1 was performed by a Seismic Qualification Review Team (SQRT) and a Pump and Valve Operability Review Team (PVORT) which consisted of engineers from the NRC staff and from Brookhaven National Laboratory (BNL). The SQRT and PVORT reviewed the equipment information contained in the Final Safety Analysis Report (FSAR) Sections 3.9.3.2 and 3.10 and visited the plant site from March 13 through March 16, 1984. The purpose of the site visit was to determine the extent to which the qualification of equipment, as installed, 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 selected for the audit. The plant site visit consisted of field observations of the actual final equipment configuration and its installation. This was followed by a review of the corresponding design specifications, test, and/or analysis documents which the licensee maintains in its central files. The field installation of the equipment must be observed, in order to verify and validate equipment modeling employed in the qualification program. In addition to the document reviews and equipment inspections, the licensee presented details of the maintenance, startup testing, and in-service inspection programs.

The following is the staff's evaluation of the adequacy of the Catawba Unit 2 equipment qualification program for safety-related mechanical and electrical equipment. In order to document the degree to which the equipment qualification program complies with the qualification requirements and criteria, the licensee provided equipment qualification information by letter dated November 21, 1985.

This evaluation addresses the safety-related mechanical equipment and electrical equipment at Catawba Unit 2 that is different from equipment at Unit 1 and which must function in order to mitigate the consequences of a design-basis accident, inside or outside containment, while subjected to the full range of normal and accident loadings (including seismic). Safety-related mechanical equipment and electrical equipment at Catawba Unit 2 that is identical to equipment at Unit 1 has been addressed in SER Supplements 2, 3, and 4.

By letter dated November 21, 1985, the licensee confirmed that the safety-related mechanical equipment and electrical equipment types and locations for Unit 2 are identical to Unit 1 except for seven items. Hence, SER Supplements 2, 3, and 4 addressing the qualification of equipment are also applicable to Catawba Unit 2.

The licensee has stated that no differences were identified in the mechanical equipment area. Seven items in the electrical equipment area have been identified as being different. These seven items are shown in Table 3.4 of this SSER. All items have qualification reference documents. Because there are a small number of items that are different, and these items are qualified, the staff finds that for practical purposes Units 1 and 2 at Catawba should be treated as identical with regard to seismic and dynamic qualification of mechanical and electrical equipment (SRP Section 3.10).

Conclusion

The staff has reviewed the Catawba Unit 2 program for seismic and dynamic qualification of mechanical and electrical equipment that is safety related. The staff finds the seismic and dynamic qualification program for safety-related mechanical and electrical equipment at Catawba Unit 2 meets the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50, Appendix B to 10 CFR 50, and Appendix A to 10 CFR 100.

3.11 Environmental Qualification for Safety-Related Electrical Equipment

3.11.4 Qualification of Equipment

3.11.4.1 Electrical Equipment Important to Safety

3.11.4.1.1 Equipment Requiring Corrective Action

The staff stated in a footnote to Table 3.2, Section 3.11, SSER 3, that the licensee has committed to relocate the area termination cabinet 1EATC9A to a mild environment prior to initial criticality. By letter dated June 6, 1985, the licensee informed the staff of its action to relocate, prior to initial criticality, only two timing relays contained in the cabinet for which qualification for a post-LOCA radiation environment had not been completed. The cabinet and its remaining components were left at the previous location. The following evaluation reflects the above relocation taken by the licensee, which was completed prior to initial criticality.

By letters dated September 12, 1984, and March 15 and April 1, 1985, the licensee provided qualification information to eliminate the need for the justification for interim operation for the following three pieces of equipment identified in Table 3.2 of the Catawba Supplemental Safety Evaluation Report 3 (SSER 3), dated July 1984.

(1) area termination cabinet 1EATC9A
(2) D. G. O'Brien electrical penetration--Type H module
(3) Valcor solenoid valve operators--70900-21-1 and 3

A staff review concluded that the information provided on this equipment is acceptable to resolve this issue.

3.11.5 Main Steam Line Break Outside Containment

By letters dated October 8, 1984, and March 15, 1985, the licensee provided information to resolve the issue of main steamline break (MSLB) outside containment (in the doghouse); this issue was also identified in SSER 3. The information provided by the licensee included a failure mode and effects analysis wherein it was shown that the main steam isolation valves (MSIVs), steam generator power-operated relief valves (PORVs), and the main feedwater isolation valves (MFIVs) in the faulted doghouse that are required to automatically actuate on a safety signal will perform their intended function for at least 30 minutes before the equipment internals exceed their qualification temperature. Furthermore, the Westinghouse core response analysis demonstrates that it is acceptable for the MSIVs, steam generator PORVs, and the MFIVs located in the faulted doghouse to fail during a main steamline break in the doghouse and that such failures would still allow the plant to be safely shut down. The staff reviewed the information provided by the licensee and concluded that it is acceptable.

The steamline break analyses in support of doghouse equipment qualification were performed with an updated but unapproved version of LOFTRAN. The version of LOFTRAN in question was used in analysis involving McGuire Units 1 and 2 and Catawba Units 1 and 2. A request for additional information was issued by an NRC letter to the licensee dated September 16, 1985. Consequently, final resolution of this issue depends on the staff review and approval of the version of LOFTRAN in question.

By letter dated November 15, 1985, the licensee partially responded to the staff request of September 16, 1985, for additional information pertinent to the steamline break analyses and the LOFTRAN code methodology. In that response, the licensee committed to provide additional information on both issues. The staff has reviewed the information that was provided and, furthermore, has initiated review of the documents that were referenced by the licensee.

The staff review, although incomplete, has progressed sufficiently that the following findings have been made:

(1) Further clarification of the November 15, 1985, material is required to complete the staff's review.

(2) The applicability of the LOFTRAN methodology to Catawba Unit 2 is expected to be confirmed, although questions remain regarding some of the detail.

(3) The review has progressed sufficiently for the staff to conclude that the MSLB issue will be satisfactorily resolved and the health and safety of the public will be protected.

Therefore, the staff concludes that the initial startup and operation of Catawba Unit 2 may proceed. However, the staff will require that before startup following the first refueling outage, the licensee shall provide the additional outstanding information identified in its November 15, 1985, letter; shall satisfactorily resolve further staff requests for clarification; and shall receive staff approval in regard to this issue. License condition 49 is added to the conditions listed in Section 1.9 of this supplement to reflect the requirement stated above.

Table 3.4 Equipment differences between Unit 1 and Unit 2

Item	Equipment description	Unit	Vendor	Model
1	Transmitter/steam generator level (N/R)*	1 & 2 2	Barton (NSSS) Rosemount	764 (Lot 2) 1153HD4PB
2	Transmitter/reactor coolant system flow	1 & 2 2 1	Veritrak (NSSS) Rosemount Tobar	76 1153HD5PB 32DP
3	Transmitter/steamline pressure	1 & 2 1	Veritrak (NSSS) Tobar	76 32DP
4	Transmitter/main feedwater flow	1 & 2 1 2	Veritrak (NSSS) Tobar Rosemount	76 32DP 1153DB6PB
5	Transmitter/main steam flow	1 2	Veritrak (NSSS) Tobar	76 32DP2212/64312
6	Transmitter/refueling water storage tank level	1 & 2 1	Veritrak (NSSS) Tobar	76 32DP2
7	Valve solenoid operator/ pressurizer power-operated relief valves	1 2	Valvor ASCO	V70900-39-3-1 MPB316E36E/E34E

*N/R denotes narrow range

4 REACTOR

4.4 Thermal-Hydraulic Design

4.4.3 Instrumentation

4.4.3.4 Instrumentation for Detection of Inadequate Core Cooling

The inadequate core cooling instrumentation (ICCI) system for each unit of Catawba Nuclear Station consists of three subsystems--subcooling margin monitor (SMM), core exit thermocouples (CETs), and reactor vessel level instrumentation system (RVLIS). The Class 1E Westinghouse microprocessor system, Model 86 inadequate core cooling monitor (ICCM-86) is utilized. Inputs from the reactor coolant system are processed by the microprocessor system and displayed by the plant computer and the qualified plasma display. The plasma display trends SMM and RVLIS for the previous 30 minutes and trends the five highest CETs per train for the previous 40 minutes. The Catawba Unit 2 ICCI system has been upgraded as described in the February 5, 1986, letter from the licensee. The same ICCI system upgrade will be done for Catawba Unit 1 during the first refueling outage.

In accordance with Catawba Nuclear Station, Unit 1, license condition 15 as stated in NPF-35 (license condition 5 as stated in Section 4.4.3.4, of SSER 2), the licensee has provided the ICCI system implementation report in an April 26, 1985, letter. The reported status follows:

(1) The ICCI system is installed. Functional testing and calibration is complete and test results are available for inspection.

(2) The system is performing in accordance with design expectations and within design error tolerances.

(3) There were no deviations of the as-built system from previous design descriptions.

(4) The recommendations of Generic Letter 83-37, "NUREG-0737 Technical Specifications," have been incorporated into the Units 1 and 2 Technical Specifications.

(5) Section 13.5.2 of Supplement 4 to the Catawba SER confirms that the emergency operating procedures (EOPs) used for operator training conform to the NRC-approved EOP guidelines (Westinghouse Owners Group Emergency Response Guidelines, Revision 1, Generic Letter 83-22).

The staff also performed a postimplementation review of the ICCI system at the Catawba site on September 25, 1985.

Conclusion

The staff has reviewed the licensee's submittals addressing conformance of the ICCI system with the requirements of NUREG-0737, Item II.F.2. On the basis of this review and the staff's postimplementation audit conducted at the Catawba site, the staff concludes that:

(1) The current redundant ICCI system for Catawba Units 1 and 2, which includes SMM, CET, and RVLIS, has been installed, calibrated, and made operational. The system installed on Unit 2 is acceptable to the staff. The licensee has committed to upgrade CETs, plasma display, and SMM for Catawba Unit 1 during the first refueling outage, in accordance with the license condition for that plant.

(2) The current Technical Specifications in use for Catawba Units 1 and 2 SMM, CET, and RVLIS are in accordance with the recommendations of Generic Letter 83-37 and are acceptable.

(3) The Catawba emergency operating procedures incorporate the ICCI in accordance with the NRC-approved EOP guidelines and are, therefore, acceptable.

The licensee is required to review its ICCI instrumentation as part of the detailed control room design review (DCRDR) in accordance with NUREG-0737, Supplement 1, requirements.

On the basis of this review and the implementation review of the ICCI installation conducted at the Catawba Nuclear Station on September 25, 1985, the staff has concluded that the ICC instrumentation installed by the licensee for Catawba Unit 2 is in compliance with the NUREG-0737, Item II.F.2, requirements and is acceptable. Thus, license condition 5 of SSER 2 is resolved for Unit 2 and remains unchanged for Unit 1.

5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing*

By letter dated January 8, 1985, the licensee submitted Volume 1 of the Inservice Inspection Program for the Catawba Nuclear Station to address license condition 2.C.(6) in Facility Operating License NPF-31 (license condition 6 in Section 1.9 of SER and supplements). The licensee indicated the estimated commercial operation date for Unit 1 to be May 1985. The licensee's submittal references Volume 2, "Detailed Inspection Plans for Catawba Unit 1," which is in course of preparation and will be issued at a later date.

The staff has evaluated the licensee's submittal and determined that the Inservice Inspection Program for Unit 1 is not complete and, therefore, is not sufficient to resolve license condition 2.C.(6). The detailed information required to evaluate compliance with 10 CFR 50.55a(g)(4) will be contained in Volume 2. Therefore, the staff retained license condition 2.C.(6), with the scheduled completion date changed to May 31, 1985, as agreed upon by the licensee in its January 10, 1985, letter. The bases for this conclusion are as follows:

(1) The licensee's complete Inservice Inspection Program will be available for review on about the estimated commercial operation date.

(2) The staff does not expect that the licensee will be required to perform inservice inspection of welds before the first refueling outage, which is estimated to occur in May 1986.

(3) The staff performed a detailed review of the licensee's Preservice Inspection Program and reported the staff's conclusions in Sections 5.2.4 and 6.6 of SSER 2. When the licensee completes Volume 2 of the Inservice Inspection Program and submits this document for review, the staff expects that the majority of the welds required to be examined during the initial 10-year inspection interval will have been examined during the preservice inspection with similar or equivalent examination techniques.

Therefore, the staff finds that extending the submittal date for the Inservice Inspection Program to May 31, 1985, does not represent a significant safety issue.

---

*By letter dated January 17, 1985, the staff transmitted this section to the licensee together with the full-power operating license for Unit 1.

5.2.4.2 Evaluation of Compliance With 10 CFR 50.55a(g) for Catawba Nuclear Station, Unit 2*

This evaluation supplements conclusions in Section 5.2.4.2 of the SER, which addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). The staff's technical review of the Unit 2 Preservice Inspection (PSI) Program was performed in a manner consistent with the similar review of Unit 1. On the basis of the construction permit date of August 7, 1975, this section of the regulations requires that a PSI Program be developed and implemented using at least the edition and addenda of Section XI of the ASME Code applied to the construction of the particular components. The components (including supports) may meet the requirements set forth in subsequent editions of this Code and addenda which are incorporated by reference in 10 CFR 50.55a(b), subject to the limitations and modifications listed therein. The licensee has prepared the PSI Program on the basis of compliance with the requirements of the 1974 Edition of the Code including addenda through Summer 1975, except where specific relief is requested.

The staff has reviewed the FSAR through Revision 14, dated January 1986; the Catawba Unit 2 PSI Program through revisions submitted on March 29, 1985; and letters from the licensee dated May 18, 1983, and February 20, March 30, and November 15, 1984. The letter dated March 30, 1984, contained a listing of requests for relief from ASME Code Section XI requirements which the licensee has determined to be not practical for both Units 1 and 2; the letter dated November 15, 1984, contained a relief request unique to Unit 2. The relief requests applicable to the reactor coolant pressure boundary address the required volumetric examination of nine pipe branch connection welds (3 and 4 inches in diameter), the updating to the requirements of later approved Code editions for the visual examination of the pressurizer cladding and the examination of support lug attachments on the pressurizer. These relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). The staff evaluated the ASME Code-required examinations that the licensee determined to be impractical and concluded that the licensee 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. In the March 29, 1985, submittal, the licensee stated that the PSI Program is essentially complete and that no additional requests for relief are expected.

On the basis of the granting of relief from these preservice examination requirements and review of the licensee's submittals, the staff concludes that the PSI Program for the reactor coolant pressure boundary at Catawba Nuclear Station, Unit 2, is acceptable and in compliance with 10 CFR 50.55a(g)(3). The detailed evaluation supporting this conclusion is provided in Appendix 6B to Section 6.

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

---

*Sections 5.2.4.2, 5.4.2.2.2, and 5.4.2.2.3 were prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

5.4 Component and Subsystem Design

5.4.2 Steam Generators

5.4.2.2 Steam Generator Tube Inservice Inspection

5.4.2.2.2 Evaluation of the Inspection Program

General Design Criterion (GDC) 32, "Inspection of Reactor Coolant Pressure Boundary," Appendix A to 10 CFR 50, requires that components which are part of the reactor coolant pressure boundary be designed to permit periodic examination and testing of important areas and features to assess their structural and leak-tight integrity. The steam generators at Catawba Unit 2 have been designed to meet the ASME Boiler and Pressure Vessel Code requirements for Class 1 and 2 components. Provisions also have been made to permit inservice inspection of the Class 1 and 2 components, including individual steam generator tubes. The design aspects that provide access for examination and the proposed inspection program must comply with the requirements of Section XI of the ASME Code, and follow the recommendations of RG 1.83, Revision 1, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," and NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Waters Reactors," with respect to the examination methods to be used, provisions for a baseline examination, selection and sampling of tubes, inspection intervals, and actions to be taken in the event that defects are identified.

Catawba Unit 2 uses Westinghouse Model D5 steam generators. In a letter dated February 20, 1984, the licensee responded to the generic problem concerning the potential for tube degradation caused by flow-induced vibration in the preheater section of Westinghouse Model D steam generators. In response to NUREG-1014, the licensee performed the approved modification on the Catawba Unit 2 steam generators, consisting of tube expansion for 124 tubes per steam generator and diversion of 10% of main feedwater flow to the auxiliary feedwater nozzle.

The licensee has also committed to perform the preservice examination of the steam generator tubing per the requirements of RG 1.83, Revision 1, and NUREG-0452, Revision 4. On the basis of these documents, the licensee is committed to examine the full length of each tube in each steam generator using eddy-current techniques to establish the baseline condition of the tubing. The examination is to be performed before initial power operation is achieved, using the equipment and techniques expected to be used during subsequent inservice examination. Therefore, the staff considers the PSI Program for the Catawba Unit 2 steam generator tubing inspection acceptable and in compliance with 10 CFR 50.55a(g)(3).

5.4.2.2.3 Conclusions

Conformance with RG 1.83, the applicable revision of NUREG-0452, and the inspection requirements of Section XI of the ASME Code constitute an acceptable basis for meeting, in part, the requirements of GDC 32.

5.4.2.3 Steam Generator Modification

Section 5.4.2.2.2 of the SER stated that the NRC staff expects that modifications will be performed on the Catawba Unit 2 steam generators before startup and that the staff will address this issue in a supplement to the SER. These modifications were required to rectify a generic problem concerning a potential for tube degradation caused by flow-induced vibration in the preheater section of Westinghouse Model D steam generators identified in a foreign plant in 1981. The staff evaluated the information submitted by the licensee relative to the changes being made to the Catawba Unit 2 Model D5 steam generators to minimize tube vibration; that evaluation follows.

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

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

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

On the basis of this extensive model test and analysis program, Westinghouse designed, verified, and implemented a modification to the steam generator to reduce tube vibratory response to preheater inlet flow excitation. Additionally, the magnitude of the flow forcing function was reduced through implementation of a preheater flow bypass arrangement in the feedwater system. To verify that the modifications reduced tube excitation and response, data from a full-scale test under simulated conservative flow and tube support conditions were studied.

These design modifications developed by Westinghouse for the preheater section of Model D4 and D5 steam generators substantially reduce tube vibration. As a result, the potential for tube wear has been reduced to within acceptable levels.

In the Model D5 steam generators in Catawba Unit 2, the modifications consist of expanding selected tubes into the baffle plates in the preheater, and splitting the feedwater flow through the auxiliary feedwater nozzle. The close support condition, resulting from tube expansion at the supports, significantly changes the response frequency and also the G-delta value (product of the peak-to-peak acceleration and root-mean-square, RMS, displacement). The G-delta parameter provides a measure of tube wear resulting from vibration. A reduced value of G-delta is indicative of diminished potential for tube wear. The split feedwater flow reduces the mass flow and velocity of the fluid in the preheater section. Both modifications combine to provide a substantial improvement by reducing the potential for tube wear.

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

Fatigue of the tubes in the preheater region that are subject to flow-induced excitation is not a concern, since the maximum resultant stresses in the tube are below the endurance limit of the material.

For areas of the tube bundle other than the preheater, parallel flow analyses were performed to determine the vibratory deflections. These analyses indicate that the flow velocities are low enough to result in negligible fatigue and vibratory amplitudes. The support system, therefore, is deemed adequate with regard to parallel flow excitation.

To evaluate cross-flow at the exit of the downcomer flow to the tube bundle and at the top of the bundle in the U-bend area, Westinghouse performed an experimental research program of cross-flow in tube arrays with the specific parameters of the Model D4/D5 steam generator. Air and water model tests were employed. The results of this research indicate that these regions of the bundle are not subject to the vortex shedding mechanism of tube excitation. Vortex shedding was found not to be a significant mechanism in these two regions for the following reasons:

(1) Flow turbulence in the downcomer and tube bundle inlet region inhibit the formation of von Kármán vortices.

(2) Both axial and cross-flow velocity components exist on the tubes. The axial flow component disrupts the von Kármán vortices.

This research program was also the basis for evaluating the fluid-elastic mechanism associated with cross-flow at the tubesheet. The evaluation showed the adequacy of the tube support arrangement.

Flow turbulence can result in some tube excitation in these regions. This excitation is of little concern, however, since

(1) maximum stresses in the tubes are at least an order of magnitude below the fatigue endurance limit of the tube material, and

(2) tube support arrangements preclude significant vibratory motion.

In summary, tube vibration has been thoroughly evaluated. Mechanical and primary flow excitation is considered negligible. Secondary flow excitation has been evaluated. From this evaluation, the staff has concluded that the proposed expansion of selected tubes and splitting the feedwater flow through the auxiliary feedwater nozzle reduces tube vibration and the potential for tube wear to within acceptable levels. Any tube wear resulting from the tube vibration would be limited and would progress slowly. This allows use of a periodic tube inservice inspection program for detecting and following up tube wear. This Inservice Inspection Program, in conjunction with tube plugging criteria, provides for safe operation of the Model D5 steam generators in Catawba Unit 2.

5.4.4 Residual Heal Removal System

5.4.4.1 Functional Requirements

In the second supplement to the Catawba Safety Evaluation Report (SSER 2), the staff reported that, in order to meet the guidance of Branch Technical Position (BTP) RSB 5-1, the licensee committed to upgrade two of the pressurizer power-operated relief valves (PORVs) and the steam generator atmospheric dump valves (ADVs) to safety grade. The licensee proposed to upgrade the qualification of the pressurizer PORVs and provide a safety-related source of nitrogen for emergency operation. The licensee also proposed to replace the pneumatic actuators of the steam generator ADVs with qualified electrohydraulic actuators. The staff reported that the licensee committed to implement the above modifications by the end of the first refueling outage for Unit 1 and before fuel load for Unit 2. The staff concludes that the proposed upgrade is acceptable.

After SSER 2 was issued, the licensee (by letter dated March 21, 1985), submitted a revision to the proposed upgrade of the PORVs and ADVs. The implementation schedule of the revised upgrade remains the same as originally planned by the licensee and accepted by the staff. The licensee's proposed upgrade of the PORVs and ADVs to safety grade follows.

(1) Pressurizer PORVs

The pressurizer PORVs provide the required safety-grade means to depressurize the reactor coolant system (RCS) to residual heat removal (RHR) entry conditions. Presently, two cold-leg accumulators (CLAs) provide nitrogen (N_2) to the two PORVs used for low-temperature overpressure protection (LTOP). This system only works below a predetermined RCS temperature. Thus, a design modification to add two safety-grade N_2 supply tanks was originally anticipated.

Subsequently, the licensee initiated a review to determine the feasibility of utilizing the CLA N_2 as the safety-grade source of gas for the PORV operation. The licensee consulted with Westinghouse to determine if any design-basis-accident condition for which the pressurizer PORVs were used also required the CLAs to perform their intended safety function.

The licensee's review considered the emergency procedures which are broader in scope than the design-basis events. The emergency procedures encompass several procedures in which the PORVs may be utilized. These procedures prioritize the available means of depressurization; normal or auxiliary spray is selected in preference to the pressurizer PORVs. When the PORVs are selected, RCS depressurization is not immediately initiated for most cases. Safety-grade N_2 to the PORVs is only required if both normal and auxiliary spray are unavailable, the normal instrument air supply is also unavailable, and time is insufficient to restore it. The licensee notes that air compressors may be manually aligned to the emergency diesel generators and the high-pressure auxiliary spray valve has been replaced with a safety-grade electric motor operator (EMO) valve.

The licensee stated that for large-break loss-of-coolant accidents (LOCAs), CLA injection occurs and the PORVs are not required. For smaller breaks, the PORVs may be used to depressurize to aid in reestablishing pressurizer level. Any resulting reduction in CLA pressure will not adversely affect post-LOCA cooldown and depressurization using Catawba emergency procedures which are based on Westinghouse Owner's Group Emergency Response Guidelines. It is the staff's estimate that because of (a) the difference in the CLA's N_2 space volume (about 350 ft^3 per CLA) and the PORV's actuator volume (on the order of 1 ft^3), (b) the reduction of the N_2 pressure from that of the CLA (400-450 psig) to that of the PORV actuator (about 80 psig), and (c) the high RCS depressurization rate resulting from opening the PORV (on the order of several hundred psig per minute), these PORVs can be operated to depressurize the primary system without affecting the operability of the CLAs. Also, sump recirculation can be used for long-term heat removal following a LOCA. For steam generator tube rupture, PORVs may be used to establish pressurizer level indication, but the CLAs are not required for mitigating the accident. On this basis, the licensee concluded that the CLAs are acceptable as the N_2 source to satisfy BTP RSB 5-1 requirements.

The plant Technical Specifications require testing the PORV's emergency N_2 supply to demonstrate the operability of the systems valves and pressure regulator and that the N_2 supply system is sufficient for proper PORV operation. This safety-guide N_2 source will not be normally aligned. Alignment for the LTOP function will remain as previously reviewed and approved by the staff. The Catawba emergency procedures will establish the conditions for alignment of CLA N_2 to the PORVs, which can be established from the control room.

The staff concurs with the licensee's conclusion and finds acceptable the proposed use of CLA N_2 as the safety-grade source for PORV operation.

(2) Steam Generator ADVs

The licensee originally proposed (Section 5.4.4 of SSER 2) to replace the existing pneumatic actuators with electrohydraulic actuators. However, after further evaluation of feasibility and reliability of the design, the licensee decided to upgrade the pneumatic actuators to safety-related status. This upgrade includes seismic and environmental qualification of the valve actuators, regulators, and solenoids, and the addition of a dedicated and seismically qualified pressurized N_2 cylinder to each ADV.

The actuators will be qualified to remain in the safe position (closed) following a main steamline break. Each two of the four ADVs and their associated N_2 cylinders will be located in the same enclosure "doghouse." The ADVs in the doghouse not affected by the steamline break will be used to depressurize the intact steam generators if depressurization is required. The two ADVs in each doghouse have independent N_2 supplies with solenoids powered from independent electrical trains.

The staff finds acceptable the upgrade of the ADVs proposed above.

The staff has reviewed the proposed revision to the upgrade of the Catawba pres-s zer PORVs and steam generator ADVs and concludes that such a revised upgrade is acceptable. By Revision 14 to the FSAR, the licensee informed the staff that the upgrade was implemented for Unit 2. The staff finds this acceptable, and therefore, license condition 36 of this SSER was resolved for Unit 2.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Containment Functional Design

(a) Ice Condenser

By letter dated July 30, 1985, the licensee requested that the partial exemption from GDC 16, 38, and 50 of Appendix A to 10 CFR 50, concerning the ice condenser, previously granted in the Catawba Unit 1 operating license be carried over to the Catawba Unit 2 operating license. The licensee stated that the safety evaluation currently contained in Catawba SSER 3, Section 6.2.1, for Catawba Unit 1 is applicable to Unit 2 and adequately covers extension of the requested exemption to Catawba Unit 2. This partial exemption relates to completion and testing of certain ice condenser items which will not be complete before entering mode 4 in accordance with Technical Specification 3/4.6.5. The licensee's justification for granting the exemotion was that since the reactor will be in cold shutdown (mode 5) and will not leave that mode until after the ice condenser items are complete, the situation is identical to those modes of operation that would be permitted were the license to be issued with the ice condenser fully operable and subsequently removed from service. The licensee further stated that for purposes of fuel loading and precriticality testing up to mode 5, operation under the exemption would, therefore, be as safe as that situation in which, for those modes of operation, the licensee fully complied with the regulations at the time the license was issued.

By letter dated January 21, 1986, the licensee submitted information to identify the special circumstances for granting this exemption to Catawba Unit 2 pursuant to the Final Rule 10 CFR 50.12 (50 FR 50764) published on December 12, 1985. The licensee stated that the ice condenser pressure suppression system which is required by GDC 16, 38, and 50 is not required to be operable when there is insufficient stored energy in the reactor coolant system to challenge containment integrity. Prior to entering mode 4, such would be the case. Additionally, it was noted that since during the time period in question there will be no fission product inventory, there would be no radiological consequences from containment failure that would result from a design-basis accident. Consequently, the licensee stated that special circumstances described by 10 CFR 50.12(a)(2)(ii) exist because application of the regulations in the particular circumstances is not necessary to achieve the underlying purpose of the rule, in that the safety function of the ice condenser is only required upon entry into mode 4 and the ice condenser will be declared operable before entering mode 4, in accordance with the Technical Specifications.

In addition to the foregoing basis, the staff finds that special circumstances exist in accordance with 10 CFR 50.12(a)(2)(v) in that the partial exemption would provide only temporary relief from the applicable regulation until initial entry into mode 4, and the licensee has made good faith efforts to comply with the regulation by providing the ice condenser and complying with the applicable Technical Specifications.

The NRC staff has reviewed the licensee's submittals regarding the applicability of the analysis provided in SSER 3, Section 6.2.1, to the safety standard now incorporated in 10 CFR 50.12(a)(1) and the 10 CFR 50.12(a)(2) special circumstances. The staff agrees with the licensee's statements, and finds that, in accordance with 10 CFR 50.12(a)(1), the requested partial exemption for Catawba Unit 2 from GDC 16, 38, and 50 of Appendix A to 10 CFR 50, as discussed above and in Section 6.2.1 of SSER 3, is authorized by law, will not present an undue risk to the public health and safety, and is consistent with the common defense and security. Furthermore, the staff finds that, in accordance with 10 CFR 50.12(a)(2)(ii) and (v), special circumstances, as discussed above, are present.

(b) Main Steam Line Break (MSLB) Inside Containment

This is a followup to the discussion contained in Section 6.2.1 of SSER 4 and to license condition 17 in Catawba Unit 1 Facility Operating License NPF-35 (license condition 46 in this supplement). By letter dated December 17, 1985, the licensee informed the staff that the confirmatory research program of tests and analyses regarding the containment response for MSLB accidents (as required by NPF-35 above) has been completed. The results were submitted to the NRC by Westinghouse Electric Corporation letter dated November 27, 1985 (Rahe to Thomas). The staff has not yet completed its review of the licensee's submittal. The staff will report the results of its continuing review in a future safety evaluation.

6.2.5 Combustible Gas Control System

By rulemaking adopted January 18, 1985 (50 FR 3498 et seq.), effective February 25, 1985, the Commission promulgated new hydrogen control requirements applicable, inter alia, to pressurized water reactors with ice condenser containments. The hydrogen control system must be capable of handling without loss of containment structural integrity an amount of hydrogen equivalent to that generated from a metal-water reaction involving 75% of the fuel cladding surrounding the active fuel region. The rule applies to all holders of construction permits for this type of reactor issued before March 28, 1979.

With respect to applicants for operating licenses who are subject to these requirements, a schedule for compliance is required prior to operation in excess of 5% power. However, completed final analyses acceptable to the staff, required by the rule, are not necessary to support full-power operation if the applicant has provided an acceptable preliminary analysis.

Finally, the Commission specifically stated in the rule (10 CFR 50.44(c)(3)(vii)(B)) "that such preliminary analyses are not necessary for a staff determination that a plant is safe to operate at full power if the staff has determined for similar plants referenced in [the]...rulemaking [i.e., Sequoyah and McGuire] that similar systems provide a satisfactory basis for a decision to support full-power operation until the preliminary analyses have been completed."

In sum, while Catawba Units 1 and 2 are subject to the new hydrogen control requirements, full-power operation may be authorized on an interim basis prior to submission and approval of a final analysis, and for applicants for an operating license as of the effective date of the rule, compliance is not required prior to operation in excess of 5% of full power.

The operating license for Catawba Unit 1 was issued on January 17, 1985, prior to the February 25, 1985, effective date of the new rule. A summary of the staff's review follows.

In Supplement 4 to the SER, the staff reported that the material provided in the licensee's May 22, 1984, submittal regarding hydrogen control measures for the Catawba Nuclear Station did not adequately resolve the outstanding issues identified in Supplement 2 to the SER. These issues involve equipment survivability for a spectrum of accidents, air return fan and ice condenser door response to upper compartment burns, and igniter operability in a spray environment. The staff further indicated that the necessary information and upgraded analyses had been requested by letter dated October 3, 1984, and that the license condition regarding hydrogen control measures would be modified to require the licensee to submit this material by April 1, 1985, for Catawba Unit 1.

In response to the staff's request for additional accident analyses, the licensee stated in a November 7, 1984, letter, that the following actions were planned to resolve the outstanding technical concerns regarding equipment survivability. The licensee would: (1) perform additional analyses of accident sequences using the Modular Accident Analysis Program (MAAP) code in lieu of the MARCH 1.1 code, (2) develop a best estimate set of hydrogen burn characteristics based on the results of the large-scale tests at the Nevada Test Site (NTS), (3) perform additional analysis of equipment survivability (thermal response) if the licensee's review of the work performed by Sandia indicates the need for such analysis, and (4) perform additional analysis of air return fan and ice condenser door response if it appears that significant upper compartment burns are possible. The contingencies in the latter two actions should be noted.

The licensee provided the results of the planned actions by letter dated March 29, 1985. In that letter, the licensee also advised the staff of its position that the design features of the McGuire and Catawba Nuclear Stations currently meet the requirements of the Final Rule on Hydrogen Control (10 CFR 50.44(c)(3)(iv)), and that no schedule need be submitted pursuant to the rule. The staff has reviewed the information provided by the licensee to determine whether it adequately resolves each element of the license condition. The results of the staff's review are presented below.

Hydrogen Control Measures

License condition 14 (Hydrogen Control Measures) in Catawba Unit 1 Operating License NPF-35 requires that:

> Before April 1, 1985, upgraded analyses and tests shall be provided on the following issues and submitted for staff review and approval:
>
> (1) thermal response of the containment atmosphere and essential equipment for a spectrum of accident sequences using revised heat transfer models
>
> (2) effects of upper compartment burns on the operation and survival of air return fans and ice condenser doors
>
> (3) operability of the glow plug igniter in a spray environment typical of that expected in the upper compartment of the containment

The license condition was placed on the Catawba Unit 1 operating license as a result of information developed following the licensing of the McGuire Nuclear Station.

At the time Supplement 7 to the McGuire SER (NUREG-0422) was issued, the licensee had performed numerous analyses of the containment atmosphere pressure and temperature response during degraded core accidents with associated hydrogen release and combustion. Many calculations were performed, using the CLASIX code, to determine the sensitivity to variations in assumed combustion parameters, assumptions regarding availability of containment safety systems, and variations in the hydrogen and steam release to the containment. The staff required that the licensee provide these studies in order to demonstrate adequacy of the igniter system to mitigate the consequences of a large fraction of degraded core accident sequences.

Although the licensee performed many CLASIX analyses, these calculations were done with the primary intent of examining the resulting peak containment atmosphere pressure during the degraded core accident transient. For the equipment survivability study, only the base case S_2D sequence analysis was used; variations on assumed flame speed and ignition concentration and combustion completeness were used. The CLASIX analyses performed using different hydrogen and steam releases or different heat removal system assumptions were not used in assessing equipment survivability. Rather than evaluate equipment performance against the containment atmosphere transients calculated for various sensitivity analyses using different hydrogen and steam releases, the licensee argued that its S_2D case represented a reasonable upper bound scenario. This conclusion was based on a comparison of hydrogen release rates as well as total hydrogen released for various accident scenarios, as predicted using the MARCH code. The staff concluded in Supplement 7 to the McGuire SER that the licensee had provided sufficient justification of equipment survivability for appropriate degraded core accident sequences even though calculations were performed only for these selected S_2D sequence. The staff reached this decision primarily on the basis that substantial margins existed between predicted temperatures and qualification temperatures. However, as noted above, the staff indicated in Supplement 7 to the McGuire SER, its intent to pursue this issue as a confirmatory item.

One approach for resolving this confirmatory issue was through the Hydrogen Burn Survival Program conducted at the Sandia National Laboratories for the NRC staff. The Sandia investigation has been completed and documented in NUREG/CR-3954. An important conclusion of this report, however, is that certain accident sequences possessing a core-melt frequency comparable to the base case S_2D sequence, produced surface temperatures in excess of the temperature to which equipment is typically qualified. Also, many of the Sandia containment analyses (NUREG/CR-3912) predicted hydrogen burning in the upper compartment of the containment, in contrast to the licensee's CLASIX analyses which predicted no burning in the upper compartment.

The staff also determined, as part of its ongoing investigation of hydrogen-related containment analysis codes, that the CLASIX code used by the licensee contained errors in the heat transfer models. The effect of these errors would cause the code to underpredict the containment atmosphere temperature which serves as the boundary condition of the determination of equipment thermal response. This problem was alluded to in the staff's October 3, 1984, letter, and was expounded on in earlier correspondence with the licensee (NRC letters dated

August 18, 1983, and May 8, 1984). Finally, confirmatory analyses performed by the staff's contractor, Los Alamos National Laboratory (LANL) (August 1, 1984), also support the findings of Sandia regarding equipment temperatures. The LANL analyses were performed using a hydrogen burn version of the COMPARE computer code, and one-dimensional heat structures to represent essential equipment.

As a result of the information obtained following the licensing of McGuire, the Catawba operating license was conditioned to required upgraded analyses of the thermal response of the containment atmosphere and essential equipment for a spectrum of accident sequences using revised heat transfer models.

In addition to requiring upgraded thermal response analyses, the license condition required that the licensee address the effects of upper compartment burns on the operation and survival of air return fans and ice condenser doors. The results of the NTS pre-mixed tests provided the principal motivation for focusing on the impact of upper compartment burns on equipment survival. In the NTS tests, thermal igniters reliably ignited hydrogen-steam-air mixtures with hydrogen concentrations as low as approximately 5.5 volume percent. When taken in conjunction with the results of Sandia MARCH-HECTR analyses (which show higher steam fractions in the lower compartment and numerous upper compartment burns), and the results of the fog analyses sponsored by the Ice Condenser Owners Group (which show an increased flammability limit in the ice condenser upper plenum), the NTS test results suggest that hydrogen burns in the upper compartment are likely for many degraded core sequences. Accordingly, the Catawba operating license was conditioned to require further review of the effects of upper compartment burns.

The license was also conditioned to require that the licensee address the matter of glow plug operability in a spray environment typical of that expected in the upper compartment. This requirement was prompted by the results of preliminary testing performed by Sandia for the NRC staff (Sandia, March 7, 1984), which indicated that glow plug igniters may be susceptible to excessive cooling by impinging containment spray droplets.

Thermal Response Analysis

Consistent with the first element of Catawba Unit 1 license condition 14, the staff requested in its October 3, 1984, letter that the licensee provide the results of analyses to determine the effects of hydrogen combustion on containment integrity and equipment survivability for the spectrum of appropriate degraded core accidents. In response, the licensee cited several deficiencies in the Sandia analyses, and provided additional information to support the adequacy of the existing utility analyses; upgraded thermal response analyses were not provided.

The licensee questioned the validity of three aspects of the Sandia work: (1) the way in which essential equipment was simulated in the HECTR analyses, (2) the hydrogen combustion assumptions used in the analyses, and (3) the use of the MARCH code to predict hydrogen and steam releases for the various sequences analyzed. The licensee asserted that the one-dimensional heat sink models used in the HECTR analyses to simulate the thermal response of equipment are overly conservative. The one-dimensional models depict the heat sinks as being insulated on one side, and do not account for heat transfer from the back side or for three-dimensional effects. This would produce surface temperatures higher than what would be expected in an actual accident situation. The licensee also contended that: (1) the assumption in the HECTR analyses that burning does not occur until the hydrogen concentration reaches 8 volume percent is unrealistically conservative (high), and is not supported by recent large-scale test results and (2) the MARCH code, used to generate the hydrogen and steam release input for the HECTR analyses, consistently overpredicts the amount of water released from the primary system. The latter contention is based on a comparison by the licensee between MARCH-computed hydrogen and steam release for the S_2D sequence, and the releases computed by the licensee using the MAAP code developed by IDCOR (Industry Degraded Core Rulemaking Program). The licensee did not provide any details of the MAAP calculation by which the staff could assess the validity of this contention.

To buttress its position that the existing utility thermal response analyses provide an adequate basis for concluding on the acceptability of the hydrogen mitigation system (HMS) installed at Catawba, the licensee provided several additional arguments. These include statements that all temperature-sensitive vital equipment for Catawba is located either outside of containment or in the dead-ended compartments within the containment, and that the sequences considered by Sandia which produce equipment temperatures beyond the loss-of-coolant-accident (LOCA) qualification temperature (S_1 sequences) should not be considered as design-basis sequences for the igniter system because they occur with a lower probability than the S_2D sequence, and quickly proceed to core melt. On the basis of the arguments, and the previously mentioned aspects of the MARCH-HECTR analyses, the licensee has concluded that additional analysis of containment and equipment thermal response is not warranted.

The staff has reviewed the information regarding thermal response analyses provided by the licensee in the licensee's letter dated March 29, 1985. On the basis of its review, the staff finds that several of the issues raised by the licensee are either unsubstantiated or would have little bearing on the overall conclusions of the report. For example, the staff recognizes that the NTS tests effectively demonstrate that ignition will occur at a hydrogen concentration lower than assumed in the Sandia and utility containment analyses, and that a downward revision of the hydrogen concentration value assumed for ignition can be justified for certain compartments in containment. Nevertheless, the staff does not consider the findings of the Sandia analyses regarding lower compartment thermal response to be invalidated by the use of the higher ignition values, or by the alleged overprediction of steam releases by MARCH, since the effect of each of these items is to shift the location of hydrogen ignition from the lower compartment to the upper plenum and the upper compartment, thereby reducing the lower compartment temperature.

On the other hand, the staff agrees with several of the points raised by the licensee, and is continuing its review in these areas. In particular, the staff recognizes that a major reason for the high surface temperature reported in the Sandia work is the use of extremely conservative models to simulate equipment, a point conceded in Sandia's report. Because proper modeling of equipment is an important element in this type of analysis, the staff intends to perform further analyses of equipment survivability using more accurate representations of equipment. The staff will defer judgment on the need for analysis of additional accident sequences by the licensee until completion of this work.

Effects of Upper Compartment Burns

Consistent with the second element of Catawba Unit 1 license condition 14, the staff requested in its October 3, 1984, letter that the licensee provide a complete evaluation of air return and hydrogen skimmer fan operability and survivability for degraded core accidents. The specific information requested from the licensee included:

(1) the identification of conditions that will cause fan overspeed, in terms of the magnitude and duration of differential pressures required to produce overspeed and hydrogen combustion events

(2) the consequences of fan operation at overspeed conditions

(3) indication to the operator of fan inoperability, corrective actions that may be possible, and the times required for the operators to complete these actions

(4) the capability of the fan system components to withstand differential pressure transients (e.g., ducts, blades, thrust bearings, housing), in terms of the limiting conditions and components

(5) an assessment of whether the requisite conditions for overspeed, tripping, or failure of the fan systems, will occur for each of the spectrum of degraded core sequences, and the impact of anticipated fan behavior on the progression of the accident

In response to the staff's request, the licensee asserted that the result of the NTS hydrogen combustion tests demonstrate that upper compartment burns, if they ever occur in a global manner, occur at hydrogen concentrations of 6.5% or less. The licensee further stated that burns occurring at this hydrogen concentration do not create sufficient differential pressure across the fans to cause them to reach synchronous speed. On this basis, the licensee concluded that no further work is required on fan survivability.

The staff concurs in the licensee's assessment that upper containment burns would occur at a hydrogen concentration of approximately 6.5% or less, but is unable to conclude on the impact of the postulated burns on fan operability without additional information. The staff will require that the licensee provide for staff review the details of the fan response calculation. Information the staff considers necessary to resolve this matter includes hydrogen combustion assumptions (e.g., flame speed, burn completion, compartment venting, containment spray heat removal) and the fan and electrical system models and assumptions. The staff will report the results of its review in a future SER supplement.

The second element of the license condition also requires an evaluation of ice condenser door survivability when subjected to hydrogen burn pressure loads. In this regard, the staff asked the licensee to: (1) provide a quantitative assessment of the pressure loading on each of the ice condenser doors created by hydrogen combustion in (a) the upper plenum and (b) the upper compartment, (2) describe and justify the assumed or calculated door positions, (3) provide an evaluation of the ultimate capability of ice condenser doors to withstand reverse differential pressures, and (4) discuss the probable failure modes and the consequences of such failures.

In response to this request, the licensee claimed that the CLASIX code predicts large pressure differentials between compartments as a result of flow model assumptions intended to maximize containment pressure response, and that the CLASIX code predictions were not confirmed by HECTR or COMPARE results. The licensee further noted that venting between compartments, combined with burning at the low hydrogen concentrations observed in the NTS tests, would effectively reduce differential pressures. On this qualitative basis, the licensee concluded that a more detailed structural analysis of the ice condenser doors need not be performed.

The staff reviewed the utility response and finds that it does not adequately address the key staff concern, namely, that upper compartment burns can produce differential pressures across the ice condenser doors in excess of their reported structural capacity. Although the staff acknowledges that the differential pressures calculated by CLASIX appear to be greater than predicted by other codes, and that upper compartment burns will likely occur at a hydrogen concentration lower than 8%, the staff is unable to conclude on the matter of ice condenser door survivability based on the available information. For example, licensee responses to staff questions regarding reverse differential pressure loads on ice condenser doors indicate an apparent inconsistency in reported values for both reverse pressure capability of the doors and the peak calculated differential pressures. The reverse pressure capability for the intermediate deck doors was reported to be 6 psid for Catawba and 2.9 psid for D. C. Cook; the peak differential pressures across these doors resulting from an upper plenum burn was reported to be 1.2 psid for Catawba and 12.6 psid for D. C. Cook. Furthermore, utility responses do not provide a quantitative assessment of the reverse pressure differential loads across each of three sets of doors resulting from an upper compartment burn. The staff estimates that the differential pressure resulting from an upper compartment burn at a hydrogen concentration of 6% would be approximately 7 to 14 psid for an assumed flame speed of 6 to 12 feet per second, respectively.

It is the staff's view that the pressure loads resulting from upper compartment burns need to be further examined, using refined modeling techniques if necessary, in view of recent tests and analyses that suggest a greater frequency of upper compartment burns than indicated in the licensee's analyses. (The MARCH/HECTR analyses do not lend themselves to this application since the analyses addressed peak compartment pressures rather than peak differential pressures.) Accordingly, the staff will request that the licensee provide the information delineated in the staff's October 3, 1984, letter, so a determination can be made regarding the survivability of ice condenser doors. The staff will provide the results of a further review of this matter in a future SER supplement.

Operability of the Glow Plug in a Spray

Consistent with the third element of Catawba Unit 1 license condition 14, the staff requested in its May 8, 1984, letter that the licensee address the need for supplementary spray shields for the glow plug igniters. In response, the licensee indicated that none of the igniters which it considers necessary for adequate coverage of the upper compartment are exposed to a spray environment. Furthermore, the only four igniters that are exposed might still be expected to function, as evidenced by the successful operation of glow plug igniters in small- and large-scale combustion tests in which sprays were present. These four exposed igniters were installed as a result of the staff's evaluation of the McGuire hydrogen mitigation system, to provide improved igniter coverage in the upper compartment.

The staff has reviewed the tests cited by the licensee to justify glow plug operability in a spray environment, namely, the small-scale tests performed by ACUREX, and the large-scale NTS tests. On the basis of its review, the staff concludes that in each case the spray conditions present in the test do not adequately simulate those expected in the upper containment. Specifically, the spray flux in the tests is substantially lower than would be expected in a containment.

Although the combustion tests cited by the licensee do not adequately demonstrate igniter operability in a containment spray environment, the results of an investigation performed by Sandia for the NRC staff appear to support this finding. The Sandia investigation included a battery of combustion tests in which a glow plug igniter was exposed to simulated containment spray fluxes both with and without the igniter spray shield installed. Additional thermal tests were conducted with an unshielded igniter in air to determine the relationship between spray flux and air velocity on igniter surface temperature. The tests indicate that the glow plug igniter is capable of maintaining a surface temperature greater than required for ignition for spray fluxes as high as approximately 1.0 gpm per square foot (in the absence of air flow) and for air velocities as high as approximately 10 meters per second (in the absence of spray flow). An assessment of the effect of combined air and spray flow on igniter temperature is currently being performed by Sandia, as are scoping analyses of upper compartment flow velocities and spray distributions. On the basis of the favorable results obtained to date, the staff will defer its judgment on the need for additional tests/analyses by the licensee, until completion of the Sandia work. The staff will report the results of its review of igniter operability in a spray environment at that time.

The staff has reviewed the information provided by the licensee to determine whether it satisfactorily resolves the three outstanding technical issues identified in Catawba Unit 1 license condition 14. On the basis of its review, the staff concludes that additional information and analyses are required from the licensee to address the effect of upper compartment burns on air return fan and ice condenser door survivability, but that further action by the licensee regarding thermal response analyses and igniter operability in a spray environment can be deferred pending completion of the staff investigation of equipment thermal response and the completion of glow plug related testing and analysis by Sandia. The Sandia work will be completed in early FY 86.

By letter dated December 17, 1985, the staff transmitted to the licensee the above Section 6.2.5 and the request for additional information on the air return fan and ice condenser door survivability. By letter dated January 6, 1986, the licensee stated that the responses to the staff's request for additional information will be provided on or before March 31, 1986.

Conclusion

As noted above, the recently adopted provisions in 10 CFR 50.44(c)(3)(iv)-(vii) apply to Catawba Units 1 and 2. However, as 10 CFR 50.44(c)(3)(vii)(B) states, "...preliminary analyses are not necessary for a staff determination that a plant is safe to operate at full power if the staff has determined for similar plants, referenced in this notice of rulemaking, that similar systems provide a satisfactory basis for a decision to support operation at full power until the preliminary analyses have been completed." The McGuire and Sequoyah plants are referenced in the notice of issuance of the rule (50 FR 3502).

On the basis of this reference and the staff's statement in Catawba SSER 4 that the hydrogen mitigation systems at the McGuire and the Catawba stations are virtually identical, the staff has concluded that Catawba Unit 1 may operate at full power, pending the completion of a preliminary analysis.

For Catawba Unit 2, for operation not in excess of 5% of full power, compliance with 10 CFR 50.44(c)(3)(iv)(A) is not required. The staff intends to address whether the three technical issues identified in the Unit 1 license condition have been satisfactorily resolved prior to issuance of a full-power operating license for Unit 2.

6.2.6 Containment Leakage Testing

Venting and Draining of Lines for Type A Tests

By letter dated July 30, 1985, the licensee requested that the partial exemption, to exclude certain piping which penetrates the containment from the venting and draining requirements in Paragraph III.A.1.(d) of Appendix J to 10 CFR 50, previously granted in Catawba Unit 1 Operating License be carried over to Catawba Unit 2 Operating License. The licensee stated that the safety evaluations currently contained in SSER 3, Section 6.2.6, are applicable, with one modification, to both Catawba Units 1 and 2, and adequately cover extension of the requested exemption to Catawba Unit 2.

This exemption would allow the licensee to use an alternative to the vent and drain method for accounting for the leakage of certain containment isolation valves. Granting this exemption would allow use during integrated leak rate tests (ILRTs) of the seal water system which has been installed at Catawba. Containment isolation valves served by this system will not be exposed to test pressure by being vented and drained during ILRTs. Other valves ("reverse" check valves) which are not served by the seal water system, but which are in the lines to be exempted from the venting and draining requirements, will be locally leakage rate tested and the results will be added to the ILRT results. Thus, all leakage will be accounted for.

The modification noted above concerns Table 6.1 of SSER 3, which contains a listing of the containment penetrations covered by the exemption. One additional penetration was recently identified (Significant Deficiency Report No. 414/85-03) that should be included in this category. The penetration is listed in the Catawba FSAR Table 6.2.4-1 as Item 63, Component Cooling Return Line, with isolation valves KC424B, KC425A, and KC279. The staff has reconsidered the venting/draining and local leak rate testing practices for this penetration and concludes that the penetration should properly be included in the tabulation of penetrations covered by this exemption. That is, the penetration will be exempt from venting and draining for type A tests, but the "reverse" check valve (KC279) must be type C tested and the measured result added to the type A test result. This additional penetration, identified above, should be incorporated into the Catawba Unit 1 exemption.

By letter dated January 21, 1986, the licensee submitted information to identify the special circumstances for granting this exemption to Catawba Unit 2 pursuant to the Final Rule 50.12 (50 FR 50764) published on December 12, 1985. The purpose of Appendix J to 10 CFR 50 is to ensure that containment leak-tight integrity can be verified periodically throughout service lifetime so as to maintain containment leakage within the limits specified. The proposed alternative test method serves this purpose in that potential leakage through the subject penetrations is measured and accounted for by the alternative test method. Consequently, the licensee stated that special circumstances described by 10 CFR 50.12(a)(2)(ii) exist because application of the regulation in the particular circumstances is not necessary to achieve the underlying purpose of the rule as the licensee has proposed an acceptable alternative test method that accomplishes the intent of the regulation. The licensee would have to expend significant resources to bring Catawba into full compliance with Appendix J and these modifications would not significantly enhance the level of safety presently attained by Catawba. Also, this exemption was previously granted on Catawba Unit 1.

The NRC staff has reviewed the licensee's submittals regarding the applicability of the analysis (with one modification) of SSER 3, Section 6.2.6, to the new standards set forth in 10 CFR 50.12(a)(1) and the 10 CFR 50.12(a)(2) special circumstances. The staff agrees with the licensee's statements above, and finds that, in accordance with 10 CFR 50.12(a)(1), the requested partial exemption for Catawba Unit 2 from the requirements of Paragraph III.A.1(d) of Appendix J to 10 CFR 50, as discussed above and in Section 6.2 6 of SSER 3, is authorized by law, will not present an undue risk to the public health and safety, and is consistent with the common defense and security. Furthermore, the staff finds that, in accordance with 10 CFR 50.12(a)(2)(ii), special circumstances, as discussed above, are present.

Bellows Testing

By letter dated July 30, 1985, the licensee requested that the partial exemption from the requirements of Paragraph III.B of Appendix J to 10 CFR 50, concerning a type B leakage rate test to be performed at full pressure (P_a, peak calculated accident pressure) on piping penetrations fitted with expansion bellows, previously granted in Catawba Unit 1 Operating License, be carried over to Catawba Unit 2 Operating License. The licensee stated that the safety evaluations currently contained in the SER and SSER 3, Section 6.2.6, are applicable to both Catawba Units 1 and 2, and adequately cover extension of the requested exemption to Catawba Unit 2.

The proposed exemption would provide alternative tests of piping penetrations fitted with expansion bellows so that there is adequate assurance that containment integrity is not affected. Appendix J requires that leak testing of expansion bellows assemblies on containment penetrations be conducted at a test pressure of P_a, the peak calculated accident pressure; for the Catawba plant, P_a is 14.7 psig. The bellows assemblies have a two-play design that allows pressurization beyond 3 to 5 psig. The exemption, therefore, is from the requirement that the test pressure equal P_a. During testing of the bellows assemblies, the inner ply is pressurized in a direction opposite to that which would be imposed in the event of an accident. Testing at P_a would jeopardize the integrity of the inner ply. Alternatively, stiffening of the inner ply to better accommodate an increased test pressure would necessitate engineering compromises contrary to overall safety. Since the expansion bellows must flex during plant heatup and cooldown, additional rigidity would increase the likelihood of inner ply failure. However, the proposed test pressure (3 to 5 psig) is sufficient for monitoring bellows assembly integrity. Therefore, from the standpoint of overall safety, plant operation with the exemption is at least as safe as requiring compliance with the leak testing requirement of the regulations.

By letter dated January 21, 1986, the licensee submitted information to identify the special circumstances for granting this exemption to Catawba Unit 2 pursuant to the Final Rule 10 CFR 50.12 (50 FR 50764) published on December 12, 1985. The purpose of Appendix J to 10 CFR 50 is to ensure that containment leak-tight integrity can be verified periodically throughout service lifetime so as to maintain containment leakage within the limits specified. This underlying purpose would not be served by application of the regulation in these particular circumstances, as testing, at P_a, of the bellows presently installed would damage them, and modification of the bellows to accept a test pressure of P_a would increase the likelihood of failure of the inner ply, which is a containment leakage barrier. Thus, the overall leak-tight integrity of the containment would not be enhanced by full application of the regulation in this case. Consequently, the licensee stated that special circumstances described by 10 CFR 50.12(a)(2)(ii) and (iii) exist because application of the regulation in the particular circumstances is not necessary to achieve the underlying purpose of the rule in that the licensee has proposed an acceptable alternative test method that accomplishes the intent of the regulation. Compliance would result in undue hardship or costs that are significantly in excess of those contemplated when the regulation was adopted and that are significantly in excess of those incurred by others similarly situated as the licensee has made a good faith effort to improve the design of bellows for mechanical penetrations. Modifications to allow full compliance with Appendix J would cause engineering compromises contrary to overall design requirements, would require the expenditure of significant resources, and would not enhance plant safety. Also, this exemption was previously granted on Catawba Unit 1.

The NRC staff has reviewed the licensee's submittals regarding the applicability of the analyses of the SER and SSER 3, Section 6.2.6, under the new provisions of 10 CFR 50.12(a)(1), and the 10 CFR 50.12(a)(2) special circumstances.

The staff agrees with the licensee's statements, and finds that, in accordance with 10 CFR 50.12(a)(1), the requested partial exemption for Catawba Unit 2 from the requirements of Paragraph III.B of Appendix J to 10 CFR 50, as discussed above and in Section 6.2.6 of both the SER and SSER 3, is authorized by law, will not present an undue risk to the public health and safety, and is consistent with the common defense and security. Furthermore, the staff finds that, in accordance with 10 CFR 50.12(a)(2)(ii) and (iii), special circumstances, as discussed above, are present.

Containment Air Lock Surveillance

By letter dated July 30, 1985, the licensee requested that the partial exemption from the requirements of Paragraph III.D.2(b)(ii) of Appendix J to 10 CFR 50, concerning air lock leakage testing, previously granted in Catawba Unit 1 Operating License be carried over to Catawba Unit 2 Operating License. The licensee stated that the safety evaluations currently contained in SSERs 3 and 4, Section 6.2.6, are applicable to both Catawba Units 1 and 2 and adequately cover extension of the requested exemption to Catawba Unit 2.

The proposed exemption would permit the substitution of an airlock seal leakage test (Paragraph III.D.2(b)(iii) of Appendix J to 10 CFR 50) for the full pressure airlock test otherwise required by Paragraph III.D.2(b)(ii) when the airlock is opened while the reactor is in cold shutdown (mode 5) or refueling (mode 6), if no maintenance has been performed on the airlock. If an airlock is opened during modes 5 and 6, Paragraph III.D.2(b)(ii) of Appendix J requires that an overall airlock leakage test at not less than the calculated peak containment pressure from a design-basis LOCA (P_a) be conducted before plant heatup and startup (i.e., entering mode 4). The existing airlock doors are so designed that a full-pressure (i.e., P_a = 14.7 psig) test of an entire airlock can only be performed after strongbacks (structural bracing) have been installed on the inner door. Strongbacks are needed because the pressure exerted on the inner door during the test pushes in a direction opposite to that of the accident pressure direction. Installing strongbacks, performing the test, and removing strongbacks requires at least 6 hours per airlock (there are two airlocks), during which access through the airlock is prohibited.

If the periodic 6-month test of Paragraph III.D.2(b)(i) of Appendix J and the test required by Paragraph III.D.2(b)(iii) of Appendix J are current, no maintenance has been performed on the airlock, and the airlock is properly sealed, there should be no reason to expect the airlock to leak excessively just because it has been opened in mode 5 or mode 6.

By letter dated January 21, 1986, the licensee submitted information to identify the special circumstances for granting this exemption to Catawba Unit 2 pursuant to the Final Rule 10 CFR 50.12 (50 FR 50764) published on December 12, 1985 The purpose of Appendix J to 10 CFR 50 is to ensure that containment leak-tight integrity can be verified periodically throughout service lifetime so as to maintain containment leakage within the limits specified in the facility Technical Specifications. The proposed alternative test method is sufficient to achieve this underlying purpose because it provides adequate assurance of continued leak-tight integrity of the airlock. In addition, at the time this section of Appendix J was revised in 1980, the staff did not contemplate the undue hardship and cost that would result from the requirement to perform a time-consuming (approximately 6 hours or more) full-pressure test before starting up from even the shortest cold shutdown during which the airlock had been used for containment entry. Because of this, the staff has already granted this same exemption to many plants, and intends to revise Appendix J to alleviate the need for further similar exemptions. Consequently, the licensee stated that special circumstances described by 10 CFR 50.12(a)(2)(ii) and (iii) exist because application of the regulation in the particular circumstances is not necessary to achieve the underlying purpose of the rule as the licensee has proposed an acceptable alternative test method that accomplishes the intent of the regulation. Compliance would result in undue hardship and costs that are significantly in excess of what was contemplated when the regulation was adopted, and that are significantly in excess of what was incurred by others similarly situated in that plant startup is delayed and unnecessary personnel radiation exposures are incurred while performing an overall airlock leakage test at full pressure. Also, the same exemption has been previously approved for similar units (Catawba 1 and McGuire 1 and 2).

The NRC staff has reviewed the licensee's submittals regarding the applicability of the analyses of SSERs 3 and 4, Section 6.2.6, under the newly revised provisions of 10 CFR 50.12(a)(1) and the 10 CFR 50.12(a)(2) special circumstances.

The staff agrees with the licensee's statements, and finds that, in accordance with 10 CFR 50.12(a)(1), the requested partial exemption for Catawba Unit 2 from the requirements of Paragraph III.D.2(b)(ii) of Appendix J to 10 CFR 50, as discussed above and in Section 6.2.6 of SSERs 3 and 4, is authorized by law, will not present an undue risk to the public health and safety, and is consistent with the common defense and security. Furthermore, the staff finds that, in accordance with 10 CFR 50.12(a)(2)(ii) and (iii), special circumstances, as discussed above, are present.

6.6 Inservice Inspection of Class 2 and Class 3 Components

6.6.1 Evaluation of Compliance With 10 CFR 50.55a(g) for Catawba Nuclear Station, Unit 1 Regarding Hydrostatic Testing After Repair

10 CFR 50.55a(g)(4) requires that throughout the service life of a pressurized water-cooled nuclear power facility, components (including supports) which are classified as ASME Code Class 1, Class 2, and Class 3 shall meet the requirements set forth in the applicable Section XI editions and addenda of the ASME Boiler and Pressure Vessel Code to the extent practical within the limitations of design, geometry, and materials of construction of the components.

In a letter dated June 3, 1985, the licensee requested relief from the hydrostatic testing after repair by replacement of two isolation valves on the boron recycle system relief valve header. This system channels discharge water from the relief valves to the boron holdup tank A or B. The two valves isolate Unit 1 from Unit 2. The licensee stated that the repair welds are equivalent to ASME Code Class 3. The relief request contained supporting technical information. In lieu of the required hydrostatic test, nondestructive examinations were proposed consisting of 100% radiographic examination and an inservice leak test. The repair welds will be hydrostatically tested at the end of the 10-year inspection interval.

The licensee has requested written relief from an examination requirement that it has determined to be impractical in accordance with 10 CFR 50.55a(g)(5)(iii). The staff has evaluated the information in the referenced letter and has determined that the examination requirement, from which relief is requested, is impractical as is discussed in the following paragraphs.

Relief Requested

Two isolation valves were replaced because of an overpressurization event that occurred during a Unit 2 hydrostatic test. The valves and the corresponding Unit 1 welds are identified as follows:

· Valve 1NB-378, Weld #1 NB121-4,3-inch, stainless steel
· Valve 1NB-395, Weld #1 NB172-5,6-inch, stainless steel.

The licensee has provided a piping and instrumentation diagram (P&ID) and sketches of the flow configuration.

The licensee requests relief from performing the required hydrostatic pressure test on Unit 1 after rewelding the lines. The applicable Code is Section XI, 1980 Edition including addenda through Winter 1980.

Code Requirement

A hydrostatic test shall be conducted subsequent to repairs or modifications by welding which penetrates the pressure boundary on piping greater than 1 inch in diameter. Section XI of the ASME Code requires, in Article IWD-5000, a system hydrostatic test pressure of at least 1.10 times the system pressure P_{sv} for systems with design temperature of 200°F or less, and at least 1.25 times the system pressure P_{sv} for systems with design temperature above 200°F. The system pressure P_{sv} shall be the lowest pressure setting among the number of safety or relief valves provided for overpressure protection within the boundary of the system to be tested.

Bases for Requesting Relief

Performing a hydrostatic test on the boron relief valve discharge header would be impractical, extremely difficult, and very costly because:

(1) A hydrostatic test would constitute isolating the boron holdup tank which would in turn require removal of the reactor vessel head and defueling.

(2) Freeze sealing the 3-inch and 6-inch lines would require cutting piping on the Unit 2 side of the isolation valves giving rise to the possibility of contaminating Unit 2 piping.

(3) Operations Procedure OP/1/A/6200/03 will preclude the closing of isolation valves 1NB66 and 1NB84 at the same time. This will ensure that the discharge header has a continuous flow to holdup tank A or B which are vented to the the atmosphere.

Proposed Alternative Examination and Test

To establish the structural integrity of the repair welds, the licensee proposed a 100% radiographic examination and an inservice leak test of welds 1BN121-4 and 1B172-5 after the valves are installed and before the system is declared operable. These welds will also receive a hydrostatic test at the end of the 10-year inspection interval.

ASME Code Case and the Requirements of the Technical Specification and 10 CFR 50.55a(g)(5)(iv)

On December 5, 1984, ASME approved Code Case N-416 "Alternative Rules for Hydrostatic Testing of Repair or Replacement of Class 2 Piping." The Code Case addresses requirements for hydrostatic testing after the repair or replacement of Class 2 piping that cannot be isolated by existing valves or that requires securing safety or relief valves from isolation. The Code Case permits the deferral until the next regularly scheduled system hydrostatic test for that system, provided that both of the following conditions are met:

(1) Before or immediately upon return to service, a visual examination for leakage shall be conducted during a system functional test or during a system inservice test in the repaired or replaced portion of the piping system.

(2) The repair or replacement welds shall be examined in accordance with IWA-4000 and IWA-7000 using volumetric examination methods (IWA-2230) for full-penetration welds or surface examination methods (IWA-2220) for partial-penetration welds.

Code Case N-416 has not been referenced in Regulatory Guide (RG) 1.147, "Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1." The ASME Code Committee made a specific decision not to include ASME Code Class 3 components in Code Case N-416. However, plant-specific approval has been granted by the Commission to licensees to apply the principles described in Code Case N-416 for the repair or replacement of ASME Code Class 1, 2, and 3 components.

The Catawba Unit 1 Technical Specifications contain a limiting condition for operation, paragraph 3.4.10, which states that the structural integrity of ASME Code Class 1, 2, and 3 components shall be maintained in accordance with Specification 4.4.10 for all modes of operation. Surveillance requirements are established by Specification 4.4.10 which cites the requirements of Technical Specification 4.0.5 which states:

> 4.0.5 Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2, and 3 components shall be applicable as follows:
>
> Inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR Part 50, Section 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR Part 50, Section 50.55a(g)(61(i)....

The requirements of 10 CFR 50.55a(g)(5)(iv) address revised inservice inspection programs and are not intended to apply specifically to licensees conducting inservice inspections during the first inspection interval. The regulation states:

> (iv) Where an examination or test requirement by the code or addenda is determined to be impractical by the licensee and is not included in the revised inservice inspection program as permitted by paragraph (g)(4) of this section, the basis for this determination shall be demonstrated to the satisfaction of the Commission not later than

12 months after the expiration of the initial 120-month period of operation from start of facility commercial operation and each subsequent 120-month period of operation during which the examination or test is determined to be impractical.

Staff Evaluation and Conclusion

The staff has determined that it is impractical to perform the Code-required hydrostatic test on Unit 1 associated with the repair by replacement of the two isolation valves on the boron recycle system relief valve header. To accomplish the hydrostatic test requirement would entail removal of the reactor vessel head and defueling. The staff finds that complying with the hydrostatic pressure tests for the repaired welds does not provide a commensurate gain in the safety of the plant.

Although the ASME Council has approved Code Case N-416 for Class 2 piping, this document has not yet been referenced in RG 1.147. However, plant-specific approval has been granted by the Commission to licensees to apply the principles described in Code Case N-416 for ASME Code Class 1, 2, and 3 components. The staff assumes that Code Case N-416 will be referenced in the regulatory guide and then similar requests for relief for impractical examinations will not be required for ASME Code Class 2 piping because the provisions of Section XI will be met. The staff concludes that Code Case N-416 provides a technically acceptable basis for deferring the hydrostatic test requirements for ASME Code Class 3 piping welds. The alternative examination and test proposed by the licensee are adequate to determine the structural integrity of the welds. The staff, therefore, concludes that relief from the hydrostatic test requirements is authorized by law and will not endanger life or property or the common defense and security and is otherwise in the public interest giving due consideration to the burden upon the licensee that could result if the requirements were imposed on the facility. Thus, the relief is granted for the repair as requested.

The relationship between the Technical Specification and 10 CFR 50.55a(g)(5)(iv) requires clarification. Section XI of the ASME Code defines the specific extent and frequency of examination of components. The Standard Technical Specifications include a limiting condition for operation associated with the performance of examinations and tests based on Section XI of the ASME Code. A licensee should not interpret 10 CFR 50.55a(g)(5)(iv) to permit 11 years from the start of facility commercial operation to identify impractical examination requirements unless the licensee is conducting examinations permitted by the Code during the last refueling outage at the end of the inspection interval.

6.6.2 Evaluation of Compliance With 10 CFR 50.55a(g) for Catawba Nuclear Station, Unit 2*

This evaluation supplements conclusions in Section 6.6.2 of the SER, which addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). The staff's technical review of the Unit 2

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

Preservice Inspection (PSI) Program was performed in a manner consistent with the similar review of Unit 1. On the basis of the construction permit date of August 7, 1975, this section of the regulations requires that a PSI Program for Class 2 and 3 components be developed and implemented using at least the edition and addenda of Section XI of the ASME Code applied to the construction of the particular components. The components (including supports) may meet the requirements set forth in subsequent editions of this Code and addenda which are incorporated by reference in 10 CFR 50.55a(b), subject to the limitations and modifications listed therein. The licensee has prepared the PSI Program on the basis of compliance with the requirements of the 1974 Edition of the Code including Addenda through Summer 1975 except where specific relief is requested.

The staff has reviewed the FSAR through Revision 14, dated December 1985; the Catawba Unit 2 PSI Program through revisions submitted on March 29, 1985; and letters from the licensee dated March 30 and November 15, 1984, and February 6, 1986. 10 CFR 50.55a(b)(2)(iv) requires that ASME Code Class 2 piping welds in the residual heat removal (RHR), emergency core cooling (ECC), and containment heat removal (CHR) systems shall be examined. These systems should not be completely exempted from preservice volumetric examination based on Section XI exclusion criteria contained in IWC-1220. To satisfy the inspection requirements of GDC 36, 39, 42, and 45, the PSI Program must include volumetric examination or a representative sample of welds in the above systems. The preservice inspection of welds on the CHR system is discussed in the licensee's letter dated February 6, 1986.

The submittal dated March 30, 1984, contained a listing of requests for relief from ASME Section XI Code requirements which the licensee has determined to be not practical for both Units 1 and 2, and the submittal dated November 15, 1984, contained a relief request unique to Unit 2. The relief requests applicable to Class 2 components address the required volumetric examination of four main steamline piping welds enclosed in guard pipe and updating to the requirements of later approved Code edition for volumetric examination of the area adjacent to 12 Class 2 pipe welds in the main steam system. These relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). (In the March 29, 1985, submittal, the licensee stated that no additional requests for relief are expected.) The staff evaluated the ASME Code-required examinations that the licensee determined to be impractical and determined that the licensee 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 review of the licensee's submittals and evaluation of the proposed alternatives for meeting these preservice examination requirements, the staff concludes that the PSI Program for Class 2 and 3 components at Catawba Nuclear Station, Unit 2, is acceptable and in compliance with 10 CFR 50.55a(g)(3). The detailed evaluation of these relief requests is provided in Appendix 6B to Section 6, which follows. The licensee has not submitted the initial Inservice Inspection Program. This program will be evaluated after the applicable ASME Code edition and addenda can be determined on the basis of 10 CFR 50.55a(b), but before the first refueling outage when inservice inspection commences.

APPENDIX 6B*

PRESERVICE INSPECTION EVALUATION, UNIT 2

I. INTRODUCTION

This appendix 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 submittals dated March 30, 1984, and November 15, 1984, the licensee requested relief from ASME Code Section XI requirements which the licensee has determined to be not practical and provided supporting information pursuant to 10 CFR 50.55a(a)(3). Therefore, the staff evaluation consisted of reviewing the licensee's submittals to the requirements of the applicable Code edition and addenda and determining if accepting the proposed alternatives to the Code requirements was justified.

II. TECHNICAL REVIEW CONSIDERATIONS

A. The construction permit for Catawba Nuclear Station, Unit 2, was issued on August 7, 1975. In accordance with 10 CFR 50.55a(g)(3), components (including supports) classified as ASME Code Class 1 and 2 have been designed and provided with access to enable the performance of required preservice examinations. The licensee has prepared the PSI Program on the basis of compliance with the requirements of the 1974 Edition of the Code including Addenda through Summer 1975, except where specific relief is requested.

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.

---

*Appendix 6A, which was added to the SER in Supplement 2 (SSER 2), is the staff's evaluation of the licensee's request for relief from certain preservice inspection requirements for Catawba Nuclear Station, Unit 1. Appendix 6B is the staff's evaluation of the licensee's same request for Unit 2.

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 before initial operation of the facility. The results of subsequent inservice examinations can then be compared with the original condition to determine if changes have occurred. If review of the inservice inspection results shows 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 that 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 preservice examination also demonstrates that the welds so examined are capable of subsequent inservice examination using a similar test method.

In the case of Catawba Nuclear Station, Unit 2, 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 in which 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 in which 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 in which 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 perservice examination.

III. EVALUATION OF LICENSEE REQUESTS

A submittal dated March 30, 1984, contained a listing of requests for relief from ASME Code Section XI requirements which the licensee has determined to be not practical for both Units 1 and 2. These relief requests (CN-1-001 through CN-1-004) were repeated in this appendix for clarity and also to show the component identification or weld numbers applicable to Unit 2. The submittal dated November 15, 1984, contained Relief Request CN-1-005 which is applicable only for Unit 2. On the basis of the information submitted by the licensee and 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 licensee has demonstrated that either (1) the proposed alternative would provide an acceptable level of quality and safety or (2) 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), alternatives to these preservice requirements are justified as follows. Unless otherwise stated, citations of the Code refer to the ASME Code, Section XI, 1974 Edition, including Addenda through Summer 1975.

A. Relief Request CN-1-001, Examination Category B-J, Class 1 Branch Pipe Connection Welds

Weld Assembly	Manufacturer's Serial Number	Branch	Size	Weld OD(")
Loop 1:				
Crossover	18836	RTD return	3" Sch. 160	6.700
Cold Leg	18837	Pressurizer spray	4" Sch. 160	7.200
		Regenerative HX	3" Sch. 160	6.700
Loop 2:				
Crossover	18840	RTD return	3" Sch. 160	6.700
Cold Leg	18841	Pressurizer spray	4" Sch. 160	7.200
Loop 3:				
Crossover	18344	RTD return	3" Sch. 160	6.700
		Regenerative HX	3" Sch. 160	6.700
Loop 4:				
Crossover	18848	RTD return	3" Sch. 160	6.700
Cold Leg	18849	Regenerative HX	3" Sch. 160	6.700

Code Requirements: Section XI, Table IWB-2600, Examination Category B-J, Item B4.6, requires volumetric examination of branch pipe connection welds exceeding 6 inches in diameter.

Code Relief Request: Relief is requested from performing the required volumetric examination on the subject welds.

Reason for Request: Ultrasonic examination is impractical because of the configuration, and radiography cannot be performed for inservice inspection because of inaccessibility. These branch connection welds would have to be redesigned and replaced to make the welds inspectable. The licensee stated that approximately 20% of the required examination could be performed and that these welds would receive an alternate liquid penetrant surface examination.

Staff Evaluation: The alternative proposed is acceptable for PSI based on the following considerations:

1. During fabrication, the subject welds have received liquid penetrant examinations on the inside and outside surfaces, a radiographic examination of the entire weld volume, plus ultrasonic examination of the entire volume of the forged nozzle in accordance with ASME Code Section III requirements.

2. For PSI, an alternative surface examination was performed in addition to the limited ultrasonic examination.

On this basis, the staff has concluded that the limited Section XI volumetric examination, the alternative surface examination, and the Section III fabrication examinations provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI at this time would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

B. Relief Request CN-1-002, Examination Category C-G, First Elbow Weld Off The Top of Each Steam Generator (4 welds total)

Steam Generator	Weld	Size
A	CW-SM-1A-C	32"
B	CW-SM-1B-C	32"
C	CW-SM-1C-C	32"
D	CW-SM-1D-C	32"

Code Requirement: Section XI, Table IWC-2600, Item C2.1, requires volumetric examination of circumferential butt welds. Table IWC-2520, Examination Category C-G, requires that 50% of the total number of circumferential butt welds at structural discontinuities be examined.

Code Relief Request: Relief is being requested from performing the required volumetric examination on the subject welds.

Reason for Request: Guard pipe over the process pipe welds makes these welds inaccessible for the Code-required examination. The licensee states that there are no alternative examinations that can be performed because of the inaccessibility of the welds.

Staff Evaluation: The staff has determined that the preservice volumetric examination of these welds totally enclosed in guard pipe is impractical.

Further, the staff concludes that the ASME Code Section III magnetic particle examination performed on the outside surface and radiographic examination on the entire weld volume during fabrication demonstrate an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI at this time would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

C. Relief Request CN-1-003, Examination Category B-H, Pressurizer Integrally Welded Supports, Seismic Lugs to Shell and Support Brackets to Shell

Code Requirement: Section XI, Table IWB-2500, Examination Category B-H, requires that 100% of all support lug attachments to Class 1 vessels shall be examined. Section XI, Table IWB-2600, Item B2.8, requires volumetric examination for integrally welded vessel supports.

Code Relief Request: Relief is being requested from performing the required volumetric examination on the subject welds.

Reason for Request: The Inservice Inspection Plan is being prepared to the requirements of the ASME Boiler and Pressure Vessel Code Section XI, 1980 Edition, Winter 1981 Addenda. Section XI, Table IWB-2500-1, Examination Category B-H, Integral Attachments for Vessels, will require surface examination of these attachment welds. Performing a surface examination for the preservice inspection will provide a basis for comparing future inservice inspection data.

Staff Evaluation: ASME Code Section XI, 1980 Edition, Winter 1981 Addenda is referenced in 10 CFR 50.55a(b). Updating to the requirements of later approved editions and addenda is permitted by 10 CFR 50.55a(g)(3)(v). The staff has determined that this request is acceptable because the alternative surface examination performed by the licensee is in accordance with subsequent editions of Section XI referenced by 10 CFR 50.55a(b).

D. Relief Request CN-1-004, Examination Category B-I-2, Pressurizer Cladding

Code Requirement: Section XI, Table IWB-2500, Examination Category B-I-2, requires a visual examination of at least one patch (36 sq. in.) of cladding on the interior clad surfaces of vessels.

Code Relief Request: Relief is being requested from performing the required visual examination on the subject cladding.

Reason for Request: The Inservice Inspection Plan is being prepared to the ASME Code Section XI, 1980 Edition, Winter 1981 Addenda. No visual examination of cladding is required by the 1980 Edition.

Staff Evaluation: ASME Code Section XI, 1980 Edition, Winter 1981 Addenda is referenced in 10 CFR 50.55a(b). Deletion of the subject visual examination is acceptable because updating to the requirements of later approved editions and addenda is permitted by 10 CFR 50.55a(g)(3)(v).

E. Relief Request CN-1-005, Examination Category C-G, Pressure-Retaining Welds in Class 2 Piping Systems

Assembly	Weld No.	Geometric Configuration	Size
Steam generator A	CW-SM-1A-F	Pipe to elbow	32"
Main steam	CW-SM-1A-I	Elbow to reducer	32"
	CW-SM-1A-K	Reducer to pipe	34"
Steam generator B	CW-SM-1B-F	Pipe to elbow	32"
Main steam	CW-SM-1B-I	Elbow to reducer	32"
	CW-SM-1B-K	Reducer to pipe	34"
Steam generator C	CW-SM-1C-F	Pipe to elbow	32"
Main steam	CW-SM-1C-I	Elbow to reducer	32"
	CW-SM-1C-K	Reducer to pipe	34"
Steam generator D	CW-SM-1D-F	Pipe to elbow	32"
Main steam	CW-SM-1D-I	Elbow to reducer	32"
	CW-SM-1D-K	Reducer to pipe	34"

Code Requirement: Section XI, Table IWC-2600, Item C2.1, requires volumetric examination for circumferential butt welds. Table IWC-2520, Examination Category C-G, requires that the area of interest include the weld metal and base metal for one wall thickness beyond the edge of weld.

Code Relief Request: Relief is requested from volumetric examination of the base metal out to one wall thickness from the edge of the weld.

Reason for Request: Because of limited accessibility resulting from guard pipe covering these welds, the volumetric examination of the full one-wall thickness beyond the edge of the weld cannot be maintained on all radiographs. The Inservice Inspection Plan is being prepared to the ASME Code Section XI, 1980 Edition, Winter 1981 Addenda, which requires ¼-in. coverage from the edge of the weld. This coverage can be obtained on the radiographs.

Staff Evaluation: ASME Code Section XI, 1980 Edition, Winter 1981 Addenda is referenced in 10 CFR 50.55a(b). The alternative proposed above is acceptable based on the updating to the requirements of later approved editions and addenda permitted by 10 CFR 50.55a(g)(3)(v).

IV. CONCLUSIONS

On the basis of the foregoing, pursuant to 10 CFR 50.55a(a)(3), the staff has determined that certain Section XI-required preservice examinations are impractical, and that the licensee 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.

The staff's technical evaluation has not identified any practical method by which the existing Catawba Nuclear Station, Unit 2, 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. Components that would require redesign to meet the specific preservice examination provisions include 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.

On the basis of the staff's 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), authorization of the proposed alternatives to these requirements is granted.

7 INSTRUMENTATION AND CONTROLS

7.5 Information Systems Important to Safety

7.5.2 Specific Findings

7.5.2.1 Postaccident Monitoring System

The licensee was requested by Generic Letter 82-33 to provide a report to the NRC describing how the postaccident monitoring instrumentation meets the guidelines of Regulatory Guide (RG) 1.97 as applied to emergency response facilities. The licensee's response to RG 1.97 was provided by letters dated September 26, 1983, and October 22, 1985.

EG&G Idaho, Inc., under contract to the NRC and with general supervision by the NRC staff, performed a detailed review and technical evaluation of the licensee's submittals. EG&G reported this work in the Technical Evaluation Report (TER), "Conformance to Regulatory Guide 1.97, Catawba Nuclear Station, Unit Nos. 1 and 2," dated December 1985 (added here as Appendix L). The staff reviewed this report and concurs with the conclusion that the licensee either conforms to, or had adequately justified deviations from the guidance of RG 1.97 for each postaccident monitoring variable except for accumulator tank level and pressure.

<u>Evaluation Criteria</u>

Subsequent to the issuance of Generic Letter 82-33, the NRC staff held regional meetings in February and March 1983 to answer licensee and applicant questions and concerns regarding NRC policy on RG 1.97. At these meetings, it was established that the NRC review would only address exceptions taken to the guidance of RG 1.97. Furthermore, should licensees or applicants explicitly state that instrument systems conform to the provisions of the regulatory guide, no staff review would be necessary for those items. Therefore, the review performed and reported by EG&G only addresses exceptions to the guidance of RG 1.97. This SER supplement addresses the licensee's submittals based on the review policy described in the NRC regional meetings and the conclusions of the review as reported by EG&G.

The staff reviewed the evaluation performed by EG&G contained in EG&G's TER and concurs with its bases and findings. The licensee either conforms to, or has acceptably justified deviations from, the guidance of RG 1.97 for each postaccident monitoring variable except for accumulator tank level and pressure. The installed pressure and level instrumentation for this variable does not meet the recommended environmental qualification (including radiation levels) for a postaccident situation. In an October 22, 1985, letter, the licensee stated as its position for Catawba Nuclear Station, that the accumulator tank level and pressure are not key variables for any design-basis events which result in a harsh environment. Therefore, the licensee stated, providing environmental qualification for the postaccident incontainment harsh environment is not required because the instruments have no postaccident safety function nor do they provide any required postaccident monitoring function. The staff disagrees. It is necessary to have knowledge of the status of these tanks during a loss-of-coolant accident (LOCA) in order to monitor whether they have discharged their contents into the reactor coolant system.

On the basis of the staff's review of the EG&G's Technical Evaluation Report and the licensee's submittals, the staff finds that the design of the Catawba Nuclear Station, Units 1 and 2, is acceptable with respect to conformance to RG 1.97, Revision 2, except for accumulator tank level and pressure.

The licensee should designate either level of pressure as the key variable to directly indicate accumulator discharge and, before startup from the next refueling outage, should provide instrumentation for that variable that is qualified per the provisions of 10 CFR 50.49. A license condition to accomplish this specfic objective is added to the Unit 2 Operating License NPF-48. Unit 1 Operating License NPF-35 has a corresponding but broader license condition. The corresponding SSER 4 license condition is 47.

8 ELECTRIC POWER SYSTEMS

8.3 Onsite Emergency Power Systems

8.3.1 AC Power Systems

8.3.1.1 Emergency Diesel Generator Reliability

8.3.1.1.1 Discussion

The licensee is seeking a full-power operating license for Catawba Unit 2. One matter which has been of concern to the NRC staff has been the reliability of standby emergency diesel generators (EDGs) manufactured by Transamerica Delaval, Inc. (TDI) at Catawba and 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 Shoreham 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 stem from inadequacies in design, manufacture, and QA/QC (quality assurance/quality control) by TDI.

Catawba Unit 2 is served by two TDI model DSRV-16 diesel engines, designated EDGs 2A and 2B. These EDGs are "V" configuration, 16-cylinder, 4-cycle, turbocharged, aftercooled engines. Each has a nameplate continuous load rating of 7000 kW, an overload rating of 7700 kW, and operates at 450 rpm with a brake mean effective pressure (BMEP) of 225 psig.

The licensee has been actively involved in the TDI Diesel Generator Owners Group, an organization formed by Duke Power Company (licensee) and 12 other utilities to resolve reliability issues stemming from the early problems with TDI engines. With the assistance of the Owners Group, the licensee has largely completed a comprehensive program to verify and enhance the reliability of the Catawba 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.

Background

On March 2, 1984, the TDI Diesel Generator Owners Group submitted a plan to the NRC staff which, through a combination of design reviews, 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 two major elements:

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

(2) 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, QA/QC, and operational surveillance and maintenance) are adequat .

The Owners Group program includes provisions for special or expanded engine tests/inspections, as appropriate, to verify the adequacy of the engines and components to perform their intended functions.

The 16 known problem areas (Phase I issues) identified by the Owners Group include the engine base and bearing caps, cylinder block, crankshaft, connecting rods, connecting rod bearing shells, piston skirts, cylinder head studs, push rods, rocker arm capscrews, turbocharger, 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 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 Catawba Unit 1 (TDI Diesel Generator Owners Group, Rev. 1, February 1985) was submitted to the staff by letter dated November 4, 1985. However, the licensee and the TDI Diesel Generator Owners Group (Owners Group) do not plan to submit a separate DR/QR report for Unit 2. With respect to the design review effort, the design review conducted on the Catawba Unit 1 engines is considered to be applicable to the Unit 2 engines. In its letter dated April 30, 1985, the licensee stated that the majority of the design review modifications recommended by the Owners Group in the DR/QR report for Catawba Unit 1 and implemented on the Unit 1 diesels would be implemented on Catawba Unit 2. The licensee also stated in its April 30, 1985, letter that the quality revalidation inspections and checks recommended by the Owners Group and any additional QR checks recommended in the Unit 1 DR/QR report would be implemented for Unit 2.

By letter dated June 21, 1985, the licensee informed the staff that 74 recommendations from the Owners Group either will not be implemented or will be implemented in modified form. This position applies to both Units 1 and 2. The 74 exceptions by the licensee involve Owners Group recommended component modifications, quality revalidation inspections, and maintenance and surveillance items.

Engine disassembly and subsequent detailed quality revalidation inspection of engine 2A were performed in Spring 1985 and reported by letter dated October 2, 1985. The inspections followed factory testing by TDI before delivery, but preceded preoperational testing at the site. Disassembly and inspection of engine 2B was performed subsequent to onsite preoperational testing (about 180 hours at loads exceeding 5250 kW). The results of the engine 2B inspections were documented by letter dated December 23, 1985.

8.3.1.1.2 Evaluation

The Owners Group program and the Owners Group findings and recommendations stemming from this program have been reviewed by Pacific Northwest Laboratory (PNL) under contract to the NRC. PNL hired several expert diesel engine consultants as part of its review staff. PNL has documented its findings in the following Technical Evaluation Reports (TERs):

- PNL-5718, "Review of Transamerica Delaval Inc. Diesel Generator Owners' Group Engine Requalification Program," Final Report, December 1985
- PNL-5600, "Review of Resolution of Known Problems in Engine Components for Transamerica Delaval Inc. Emergency Diesel Generators," December 1985
- PNL-5444, "Review of Design Review of Quality Revalidation Report for the Transamerica Delaval Diesel Generators at Comanche Peak Steam Electric Station Unit 1," October 1985

The staff will shortly issue (in early 1986) a formal safety evaluation report (SER) containing its final generic conclusions pertaining to the Owners Group findings and recommendations. That generic SER will incorporate the aforementioned PNL reports by reference. In the meantime, the staff has reviewed the subject PNL reports and concurs with the major PNL findings and recommendations therein. These findings and recommendations have been incorporated by the staff into this SER supplement.

Section A below focuses on the licensee's actions to resolve known significant problem areas identified by the Owners Group, namely Phase I issues. Section B addresses the staff's evaluation of the load capability of the TDI DSRV-16 model engines installed at Catawba. Section C goes beyond Phase I issues to address the overall status of the DR/QR program at Catawba Unit 2, including Phase II issues. Section D addresses the issue of engine maintenance and surveillance 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. Finally, Section E focuses on actions taken by the licensee to resolve two recent failures of the No. 7 main bearing in EDG 2B.

(A) RESOLUTION OF KNOWN PROBLEMS IDENTIFIED BY THE OWNERS GROUP

(A.1) Air Start Valve Capscrews

Problems with the air start valve capscrews coming loose were experienced at Shoreham and Grand Gulf. These problems have been attributed to the capscrews "bottoming out" inside the hole in the cylinder head because the capscrew was excessively long. In response to these problems, TDI and the Owners Group have recommended that all capscrews be shortened from 3 inches to 2-3/4 inches to preclude bottoming out of the capscrews. It was also recommended that the capscrews in each engine be 100% sample inspected for proper length and for proper torque (DR/QR report for Catawba Unit 1). In addition, the maintenance/surveillance (M/S) program recommended by the Owners Group includes torque/retorque procedures to ensure that there is no loss of preload as a result of creep of the copper head gasket material at operating temperature.

These recommended actions were reviewed generically by PNL in PNL-5600. On the basis of its review of this report, the staff concludes that the above actions will preclude failures of the capscrews. The recommended QR inspections have been completed for the Unit 2 engines with the exception that a 25% sample of capscrews (rather than a 100% sample) was inspected for length. However, because a 100% sample inspection of capscrew length was performed on engine 1A and a 25% sample on engines 1B, 2A, and 2B, and because the results of these inspections confirmed that the capscrews had been properly modified, the staff concurs that adequate sampling has been performed on the capscrews. On the basis of the above, the staff concludes that the air start capscrews at Catawba Unit 2 are adequate for nuclear service.

(A.2) Auxiliary Module Wiring and Terminations

TDI's Service Information Memorandum (SIM)-361 (Rev. 1) notified the engine owners of potentially defective engine-mounted cables associated with the Woodward governor/actuator and the Air-Pax magnetic pickup. This memorandum led the Owners Group to question the suitability of all Class 1E auxiliary module wiring and terminations currently installed on the diesel engines. Of special interest was the suitability of this wiring with respect to flame-retardancy of the insulation, qualification to industry standards, routing of conduit, compatibility with circuit requirements, and the need for special requirements such as shielding.

Stone & Webster Co. (SWEC) evaluated this issue on behalf of the Owners Group (DR/QR report for Catawba Unit 1). On the basis of its review, SWEC recommended

(1) implementation of TDI SIM-361 concerning replacement of potentially defective wiring

(2) replacement of certain Kyner-insulated, 14 AWG wire with wire qualified to IEEE 383-1974

(3) verification that installed States-Type NT sliding link terminal blocks were manufactured during time period other than 1974 to 1976 in accordance with NRC IE Information Notice 80-08, dated March 7, 1980. The staff's contractor, PNL, concurred with the SWEC findings and recommendations (PNL-5600, December 1985).

The licensee reported that items 1 and 2 above have been completed for all diesels at Catawba (letters dated October 2, 1985, and January 13, 1986).

The licensee stated in its letter dated October 2, 1985, that it does not intend to verify the manufacturing date of the TDI terminal blocks (item 3 above). The licensee also stated that it has a program for inspecting States sliding link terminal blocks during installation and each time the link is operated.

The staff believes that the licensee has not adequately justified not implementing the Owners Group recommendation. The staff points out that the intent of the Owners Group recommendation was to revalidate the quality of the engine components in advance of operational service rather than to revalidate quality on the basis of whether or not problems occur in nuclear standby service.

The staff concludes that item 3 above should be fully implemented for Catawba Unit 2. As recommended by PNL, these actions should be accomplished by the first refueling outage to ensure the adequate performance of the wiring and terminations over the life of the plant (see Section 8.3.1.1.3(D) of this supplement).

(A.3) Connecting Rods

DSRV connecting rods have experienced a few isolated failures of the connecting rod bolts and of rod boxes in non-nuclear service. On the other hand, many rods have experienced tens of thousands of hours without failure. The bulk of this experience is for engine loads ranging to about 90% of full rated load. Corresponding stress levels range to about 95% of stresses at full rated load.

TDI has attributed a number of the bolt and rod failures to the low assembly torques that had been specified. TDI has increased the torque specifications, and has stated that there have been no instances of failure when the specified torque had been applied. The Owners Group could not unequivocally confirm the TDI claim, since two cracked rods were found in non-nuclear service during the period when the higher torque specifications are supposed to have been in effect. The staff recognizes, however, that these two rods may not have been torqued to the TDI specification.

Connecting rods were inspected in both Unit 2 engines as part of the quality revalidation program. These inspections included penetrant inspection of rod box external surfaces and wrist pin bushings, as well as magnetic particle inspection of the connecting rod bolts. However, eddy-current inspection of the link rod box internal threads, as recommended by the Owners Group, was not performed on the 2A engine and was only performed on four rods in the 2B engine. In view of the limited number of hours accumulated on the Unit 2 engines to date and the favorable results from the inspections that were performed, the staff concludes that additional eddy-current inspection of the connecting rods is not necessary at this time. However, the staff and its contractor, PNL, have concluded that the bolt holes subject to the highest stresses (i.e., the pair immediately above the crankpin) should be examined with the appropriate nondestructive method during each major 5-year engine disassembly and inspection to verify the continued absence of cracking (see Section D.2.2 below).

As indicated by operating experience and by analysis, correct preload of the connecting rod bolts is critical to preventing service-induced failures. To minimize uncertainties associated with conventional torquing procedures to establish preload, the licensee's assembly procedures call for taking in situ length measurements of the bolt length using ultrasonic techniques, thus providing a direct rather than indirect indication of preload.

In accordance with Owners Group recommendations, the licensee has inspected the link rod-to-pin clearances, while the link rod bolts are torqued to 1050 ft-lb. The Owners Group has concluded that zero clearance rather than the 1.5-mil clearance allowed by TDI must be maintained to ensure against failures of the link rod bolts that have been observed in non-nuclear service. The licensee noted in its letter dated January 13, 1986, that a feeler gauge is employed to measure this clearance and that it is, therefore, impossible to physically measure zero clearance. Some acceptance criteria have to be specified. Therefore, the licensee noted that its procedure requires that a 1.5-mil feeler gauge cannot be placed between the link rod pin and link rod with 1050 ft-lb torque applied to the bolts. The licensee stated that it consulted with the Owners Group consultant, Failure Analysis Associates (FaAA), on this matter and that FaAA agrees that the licensee's procedure is acceptable.

The licensee has not implemented an Owners Group recommendation to measure connecting rod bow and to compare the measurement with an acceptance criterion also developed by the Owners Group. The staff is not aware of any TDI connecting rod or connecting rod bearing failures that resulted from excessive bow. However, because of concerns that have existed regarding QA by TDI, the intent of the QR program was to investigate beyond known problem areas to confirm acceptable "as-manufactured" quality. The Owners Group has recommended that these inspections be performed to ensure against excessive bow that could lead to connecting rod bearing misalignment.

The staff endorses the Owners Group recommendation and concludes that bow measurements should be performed when the first major engine disassembly occurs in approximately 5 years. In the meantime, the licensee has confirmed that no significant evidence of misalignment was observed on any of the connecting rods after 180 hours of engine 2B testing at the site. On this basis and because of the absence of known connecting rod bow-related problems, the staff concludes there is adequate basis to defer the connecting rod bow measurements to the first major engine disassembly in approximately 5 years, and there is little likelihood of a bow-related problem occurring during the interim.

The staff's contractor, PNL, concurs with the Owners Group findings and recommendations concerning connecting rods, but offers additional recommendations concerning maintenance and surveillance as discussed in Section D.2.2 below (PNL-5600, December 1985). Subject to the connecting rod bow measurements as defined above, and implementation of an acceptable maintenance and surveillance program as discussed in Section D below, the staff concludes that the connecting rods are adequate for nuclear service.

(A.4) Connecting Rod Bearing Shells

Eleven-inch-diameter bearing shells in the TDI DSR-48 engines at Shoreham cracked after 600-800 hours of operation. Scanning electron microscopy of the fracture surface of one of the cracked bearings revealed voids about 0.02 to 0.03 inch in diameter which appeared to be the initiation sites for the cracks. Owners Group analyses have established that the stress levels in the 13-inch-diameter bearing shells in use in the Catawba DSRV engines are about 50% of those in the 11-inch Shoreham bearings. On the basis of these analyses, the Owners Group has developed acceptance criteria regarding the maximum allowable void sizes in the aluminum bearings which could be tolerated without degrading their fatigue performance (DR/QR report for Catawba Unit 1). All connecting rod bearings for Unit 2 have been inspected by radiography to ensure compliance with these criteria as part of the quality revalidation program. In addition, each bearing was penetrant (PT) inspected to verify the absence of cracks.

PNL concurs with the Owners Group findings and recommendations concerning the connecting rod bearing shells (PNL-5600, December 1985). However, as discussed in Section D.2.3 below, PNL recommends that an oil contamination analysis be performed on a regularly scheduled basis as recommended by the oil supplier.

PNL has also suggested that the licensee consider increasing the oil pressure to the connecting rod bearings to the level used in the Grand Gulf engines (about a 10% increase in oil pressure). This suggestion is offered by PNL as a possible means to prolong bearing life. However, PNL agrees that Owners Group recommended periodic inspections will provide for timely detection of bearing wear before it could affect the operability of the bearing. The staff concludes that action by the licensee to increase oil pressure is optional.

On the basis of the above discussion, and subject to implementation of an acceptable M/S program as identified in Section D below, the staff concluded that the connecting rod bearing shells at Catawba Unit 2 will be acceptable for nuclear service.

(A.5) Crankshafts

The staff's contractor, PNL, has reviewed generic issues pertaining to DSRV-16 crankshafts and documented its findings in PNL-5600 (December 1985). The NRC staff concurs with the findings of the PNL report.

On the basis of the PNL evaluation, PNL and the NRC staff have concluded that the DSRV crankshafts are adequate for nuclear service at full TDI-rated load (7000 kW continuous plus 10% overload). This finding is subject to implementation of PNL recommendations concerning operating speed as discussed below and periodic maintenance inspections and engine surveillance as discussed in Section D.2.4 of this SER supplement.

The Catawba Unit 2 crankshafts and torsional systems are reported to be identical in design to those for Unit 1 (letter dated January 13, 1986). For this reason, the torsiograph testing performed for Unit 1 was not repeated for the Unit 2 engines. The Unit 1 torsiograph test indicated that the DEMA (Diesel Engine Manufacturers' Association) allowable stresses are met at rated load and overload conditions. The torsiograph also indicated the presence of a 4th order critical speed at 429 rpm. PNL has found that the effect of the 4th order critical speed varies with the extent of imbalance between individual cylinders. For this reason, PNL has recommended that the DSRV crankshafts should not be operated more than a few rpm below 450 rpm under steady-state conditions. The staff is requiring that the licensee implement appropriate precautions in its operating and emergency operating procedures to comply with this recommendation (see Section 8.3.1.1.3(B) in this supplement).

The licensee has reviewed the material certification reports for the Unit 2 crankshafts and verified that the material properties are within design specifications. In addition, the licensee has performed fluorescent liquid penetrant inspection of the oil holes in the most limiting No. 4, 6, and 8 main journals of each crankshaft as recommended by the Owners Group.

On the basis of the above, the staff concludes that the crankshafts are adequate for service at rated load and overload conditions. This finding is subject to implementation of an acceptable M/S program as discussed in Section D below, and adoption of precautionary notes in the engine operating and emergency procedures against operation of the engines more than a few rpm below 450 rpm.

(A.6) Cylinder Block

Cracks have been reported in cylinder blocks of TDI DSR-4 and DSRV engines in both nuclear and non-nuclear service. Of primary concern are "stud to stud" cracks of the kind that were observed in the "old" Shoreham EDG 103 block and that extended between stud holes of adjacent cylinders or ran from a stud hole down the front of the block. Experience has shown that such cracks are preceded by "ligament cracks" of the type that have been observed in all three Shoreham engines.

On the basis of the results of strain gauge tests and calculations using two-dimensional analytical models, Failure Analysis Associates (FaAA) has reported that for material exhibiting minimum acceptable tensile strength, initiation of "ligament cracks" is predicted to occur after accumulating operating hours at high load and/or as a result of engine starts to high load (FaAA Report 84-9-11, "Design Review of TDI R-4 and RV-4 Series Emergency Diesel Generator Cylinder Blocks", dated December 1984). Ligament cracks result in increased stress and thus increase the potential for crack initiation between the stud holes of adjacent cylinders. Such stud-to-stud cracks are considered to be more serious than ligament cracks, since they can potentially degrade the overall mechanical integrity of the block and its ability to withstand piston firing pressures.

As recommended by the Owners Group, the licensee inspected all cylinders for ligament cracks and stud-to-stud cracks (letters dated October 2 and December 23, 1985, from the licensee). The liner landing for four cylinders in each engine was also PT inspected. No significant indications were found during any of these inspections. In addition, replica tests were performed at various block locations which indicated normal gray cast iron, Class 40, with no evidence of degenerate (Widmanstaetten) graphite microstructure. The presence of Widmanstaetten graphite is be believed to have been a major factor leading to the early appearance of stud-to-stud cracks at Shoreham.

An FaAA cumulative damage analysis (FaAA, December 1984) has indicated that given the existence of ligament cracks and the absence of stud-to-stud cracks before a loss-of-offsite power/loss-of-coolant accident (LOOP/LOCA), even if a stud-to-stud crack were to initiate during such an event, the crack would not propagate sufficiently during the event to impair the operability of the engine. The Owners Group has recommended that the block be periodically reinspected for ligament cracks at intervals determined in accordance with the cumulative damage methodology developed by FaAA (December 1984). Should ligament cracks be detected in the future, the Owners Group has recommended that the absence of stud-to-stud cracks should be verified after any period of operation in excess of 50% of engine nameplate rated load.

As recommended by the Owners Group, the licensee has also performed measurements of the cylinder liners and cylinder liner landing areas to assess liner proudness above top of block and radial clearance between the liner and the block. The block and liners have not been remachined to conform with the latest TDI specification.

The licensee has stated in phone conversations with the staff that the actual Catawba block dimensions are within the range considered in the aforementioned cumulative damage analysis performed in accordance with the aforementioned FaAA report. The DR/QR report for Catawba Unit 1 makes a similar statement for the Unit 1 blocks. The staff has been unable to substantiate these statements in its review of the FaAA report. However, considering that the blocks have been shown to be free of cracks and of Widmanstaetten graphite and that the engines will be operated at about 82% of nameplate rated load, the staff finds that the engine blocks in their present configuration are adequate through at least the first refueling outage. The staff will require that the licensee submit, before restart from the first refueling outage, a cumulative damage analysis performed in accordance with the procedure in the aforementioned FaAA report and which verifies the acceptability of the as-built dimensions of the Catawba block. Alternatively, the block dimensions should be modified as necessary to meet the latest TDI specification (see Section 8.3.1.1.3(A) below, "Licensing Conditions").

The staff's contractor, PNL, concurs with the Owners Group findings and recommendations concerning the engine block (PNL-5600, December 1985), subject to a few recommendations concerning the maintenance and surveillance as discussed in Section D.2.5 of this supplement. Subject to verification of dimensional adequacy as described above and implementation of an acceptable maintenance and surveillance (M/S) program as discussed in Section D below, the staff concludes that the Catawba Unit 2 engine blocks are acceptable for nuclear service.

(A.7) Cylinder Heads

Numerous instances of cracks and leaks in TDI cast steel cylinder heads have been reported in both nuclear and non-nuclear service. Most cracks have been observed to have originated at the stellite-faced valve seats. However, four small jacket water leaks have been experienced in the Catawba Unit 1 engines resulting in water leaking into the fuel injector nozzle cavity. Subsequent metallurgical examination of one of these heads revealed the leak resulted from cracks propagating from a weld plug that had been used to repair the injector bore during manufacture.

As recommended by the Owners Group, the licensee has inspected each of the cylinder head fire decks and valve seats to verify the absence of cracks. In addition, the fire-decks were ultrasonically inspected to verify proper thickness. The licensee also performed eddy-current inspection to identify existing plug welds. Five heads in the 2A engine were determined to have plug welds and were replaced consistent with the position taken earlier by the staff and PNL with regard to the Catawba Unit 1 heads.

As documented in the licensee's October 2, 1985, submittal for engine 2A, a new weld repair procedure has been developed as shown on TDI drawing 102718, Revision 0. The weld repair of the cylinder heads consists of welding a plug into the head, stress relieving the weld, and machining the injector port backside of the plugout, so that the repair is a full penetration weld. Cylinder heads at Catawba that have been repaired in this fashion are stamped 1NR. The full penetration weld eliminates the crack starter found in previous partial penetration weld repaired heads. Postweld stress-relieving reduces welding residual stresses to low levels. Two of the five replacement heads for engine 2A contain these full penetration welds. On the basis of the above, the staff considers these full penetration weld repairs to be acceptable.

The staff's contractor, PNL, has concurred with the Owners Group findings and recommendations (PNL-5600, December 1985). However, PNL has recommended additional maintenance and surveillance actions as is discussed in detail in Section D.2.6 below. Consistent with the PNL recommendations and to further verify the absence of cracks that may allow water leakage into the cylinder, the staff is requiring that the surveillance program for TDI engines include provisions for air rolling of the engine at appropriate intervals with open cylinder cocks before and after each planned operation (see Section D below). The staff has concluded that such air rolls should be performed 4 to 8 hours, and again 24 hours, following any engine operation and, thereafter, before any planned start. On the basis of the above, the staff concludes that the Unit 2 cylinder heads are acceptable for nuclear service.

(A.8) Cylinder Head Studs

Isolated failures of cylinder head studs have been reported in non-nuclear service. TDI has attributed these failures to inadequate preloading. TDI's position is consistent with analyses conducted on behalf of the Owners Group indicating that the studs are of adequate design. The staff's contractor, PNL, also concurs with this position (PNL-5600, December 1985)

As recommended by the Owners Group, a 25% sample of the studs was visually inspected for engine 2A with no significant indications. The licensee has confirmed that the studs have been torqued in accordance with procedures recommended by the Owners Group in a letter dated July 3, 1984 (see letter dated January 13, 1986).

On the basis of the above, the staff concludes that the cylinder head studs are acceptable for their intended service.

(A.9) Engine Base and Bearing Caps

Cracks were reported in the engine base at Shoreham because of improper stud removal and in marine service because of insufficient stud preload. A nut pocket failure was also reported in non-nuclear service from the presence of nonferrous impurities in the engine base casting.

The staff's contractor, PNL, has completed its review of the proposed generic Owners Group technical resolution of engine base and bearing cap issues. PNL's findings are documented in PNL-5600 (December 1985). PNL concurs with the Owners Group finding that the engine base components are adequate, provided that the base casting and bolting components meet their material and dimensional specifications and that the torque specifications are met.

As recommended by the Owners Group, elongation measurements of the bearing cap studs have been completed for all studs in engine 2B, but were only performed for bearing caps 4, 6, and 8 in engine 2A. All breakaway torques measured on the Catawba engines were within the specified range. Furthermore, inadequate preload does not appear to be associated with two failures of the No. 7 main bearing which occurred recently in engine 2B and which are discussed more fully in Section E below. The licensee has committed to check the preload in the remaining studs in engine 2A during the first refueling outage.

Extensive dimensional and visual inspections of the base and bearing caps in engine 2B, particularly in the vicinity of the No. 7 main journal, have been performed as part the failure evaluation of the No. 7 main bearing. These are discussed further in Section E below. In addition, liquid penetrant (LP) inspection of saddles 6, 7, and 8 was performed as part of the failure investigation.

Even though not an Owners Group recommendation, the staff is requiring the licensee to verify that the engine base material for both engines has normal and acceptable microstructure for Class 40 gray iron. This check is being required in view of the number of instances where degenerate Widmanstaetten graphite microstructure has been found in cylinder blocks of engines at other sites (see Section 8.3.1.1.2(A.6) of this supplement).

The staff notes that the licensee has not implemented the Owners Group recommendation to check the bearing cap studs and nuts for proper material. The licensee justified this on the basis that elongation measurements indicate that the studs exhibit the expected elongation for a given applied load and, furthermore, that the bearing cap mating surfaces show no evidence of fretting. However, the staff does not agree that this provides satisfactory evidence that the studs are of proper material. For example, many kinds of steel will exhibit a similar modulus of elasticity, but will vary significantly in terms of their hardness, fatigue resistance, and resistance to stress corrosion cracking. The intent of the Owners Group recommendation was to ensure that the studs and nuts were fabricated from the correct material given the QA/QC deficiencies which were known to exist at TDI. However, in view of the fact that the staff is not aware of any materials-related difficulties with TDI bearing cap studs in nuclear service and the fact that these studs have experienced several hundred hours of service in the Catawba engines with no known difficulty, the staff believes this matter to be strictly a confirmatory issue and that the material check can be deferred until the first refueling outage without undue risk of a bearing cap stud failure (see Section 8.3.1.1.3(D) of this supplement).

Subject to additional inspections as noted above, to an acceptable maintenance and surveillance (M/S) program as identified in Section D below, and to satisfactory resolution of the main bearing problem discussed in Section E below, the staff concludes that the engine base, bearing caps, and fasteners are adequate for nuclear service.

(A.10) <u>High-Pressure Fuel Lines</u>

High-pressure fuel lines at Shoreham and Grand Gulf experienced failures caused by a draw seam on the inside diameter. Draw seams are defects introduced during manufacturing of the fuel line and extending over the entire length of the tube, or at least a significant portion of it.

As recommended by the Owners Group, the licensee performed an eddy-current inspection of the ends of each fuel line and replaced three lines on engine 2A with recordable indications. The staff's contractor, PNL, reviewed the Stone & Webster Co. (SWEC) report (April 1984) concerning the fuel oil injection tubing which was prepared on behalf of the Owners Group. PNL concluded that the fuel lines at Catawba were acceptable subject to enforcement of a 0.003-inch limit on flaw depth and to PNL-recommended maintenance actions as discussed in Section D.2.8 below. The DR/QR report for Catawba Unit 1 indicates that the licensee is enforcing the 0.003-inch limit.

PNL has also recommended that the fuel lines be shrouded by the first refueling outage to prevent engine fires in the event of a tubing leak. In addition, PNL has recommended that any replacement tubing to be installed be fabricated from SAE-1010 steel rather than SAE-1008 steel. On the basis of SWEC's and PNL's conclusion that tubes with flaws less than 0.003-inch deep are not subject to crack propagation, the staff concurs with PNL that these actions need not be implemented before an operating license is issued. The staff will make its final conclusion concerning whether future implementation of these PNL recommendations should be optional or required when it issues its final generic safety evaluation report concerning technical resolution of the TDI issue. However, on the basis of the present evaluation, the staff concludes that the high-pressure fuel lines at Catawba Unit 2 are acceptable for service for at least one refueling cycle. Staff conclusions pertaining to actions needed to support operation beyond the first refueling will be addressed in the aforementioned forthcoming generic safety evaluation report.

(A.11) Jacket Water Pump

Two jacket water pump shafts for DSR-48 engines at Shoreham failed as a result of fatigue cracking initiating at a keyway on the shaft. The pumps for the DSRV-16 engines at Catawba are of a different design and are larger than the DSR-48 pumps. These pumps have accumulated several hundred hours of service at Grand Gulf and at Catawba and no problems have been reported. Although the Owners Group found that design modifications were necessary for the DSR-48 design (used at Shoreham), no design modifications were recommended for the DSRV-16 pumps. The staff contractor, PNL, concurs with the Owners Group finding that the DSRV-16 jacket water pumps are adequately designed (PNL-5600, December 1985). The Owners Group did recommend revising the installation procedures to ensure that the external spine on the individual pump shaft would not be over- or undertorqued (DR/QR report for Catawba Unit 1, Appendix II).

The jacket water pumps were not inspected in detail at either of the Catawba Unit 2 engines, but the Unit 1A engine was inspected in accordance with Owners Group recommendations with no adverse findings. The Unit 2A and 2B water pumps were checked for proper torque on the impeller nut and the spline nut.

On the basis of the above and noting in particular the good operating experience with DSRV jacket water pumps, the staff concludes that the jacket water pumps at Catawba are adequate for nuclear service.

(A.12) Piston Skirts

Inspections revealed that 4 of 16 type AN piston skirts in the Catawba 1A engine had cracks at the circumferential rib to piston pin boss fillet. As a result, all piston skirts for the Catawba Unit 1 and Unit 2 engines have been replaced with type AE piston skirts.

The AE piston skirt design was introduced by TDI in 1982 to alleviate problems with the AN design. It incorporates an increased stud boss thickness (relative to "modified" AF, AH, and AN piston skirts) and a stress relief to relieve residual stresses believed to have been responsible for the observed cracking in AN skirts. Owners Group analyses indicate stress levels to be substantially reduced over earlier skirt designs. Furthermore, operating experience provides considerable confidence that this design will give adequate service. Two type AE pistons were run in a TDI test engine for 622 hours at 514 rpm and at a peak firing pressure 20% higher than in TDI engines in nuclear service. The 622 hours of operating time correspond to 9.6×10^6 stress cycles. Subsequent inspections revealed no cracks. In addition, type AE pistons were installed in the Shoreham EDG-103 engine during a 746-hour endurance test (10^7 stress cycles) at 3300 kW. Again, subsequent inspection revealed no evidence of crack initiation. The staff's contractor, PNL, has concluded that operating experience provides convincing evidence that the piston skirts are of adequate design (PNL-5600, December 1985).

The licensee performed liquid penetrant (LP) and magnetic particle testing (MT) of all piston skirts in accordance with Owners Group recommendations; the results were satisfactory.

On the basis of the above, the staff concludes that the piston skirts are adequate for full rated load conditions.

(A.13) Push Rods

Originally supplied push rods and numerous TDI engines experienced cracks in the weld joining the rod to the rod ends. In response to these problems, new design push rods with friction welds were installed in the Catawba diesels.

Owners Group analyses have substantiated the adequacy of the friction weld design. In addition, the friction weld design has experienced in excess of 900 hours in the Catawba Unit 1 engines with no sign of cracking. The staff contractor, PNL, has concurred with the adequacy of the friction weld design (PNL-5600, December 1985).

The licensee has inspected each of the push rods to confirm that they are the friction weld design. LP inspection was performed on each of the welds.

On the basis of the above considerations and subject to periodic visual inspections at each 5-year major engine disassembly (see Section D below), the staff concludes that the push rods at Catawba are acceptable for nuclear service.

(A.14) Rocker Arm Capscrews

Isolated instances of rocker arm capscrew failure have been reported, including a reported failure at Shoreham. TDI attributed these failures to inadequate preload. Analyses performed on behalf of the Owners Group indicate that the capscrews are adequate if properly preloaded. The staff's contractor, PNL, has reviewed and concurs with this conclusion as documented in PNL-5600, December 1985.

The licensee reported that all capscrews were visually and MT inspected and found to be satisfactory with one exception. One capscrew contained an MT indication and was replaced. All capscrews were subsequently installed to proper torques.

Telephone conversations with the licensee's representatives indicated that the indication which was found had an axial orientation and was not associated with any geometric stress raiser. The indication appeared to be a subsurface indication in that it could not be seen visually at 50 to 100X magnification. The licensee will be required to confirm this information by letter before initial plant criticality is achieved (see Section 8.3.1.1.3(A) of this supplement). However, on the basis of the above, the staff concludes that the subject indication occurred during fabrication or installation and was not a service-induced flaw.

Sample hardness and material checks recommended by the Owners Group have not yet been performed, but will be performed at the "first availability" (licensee's letter dated January 13, 1986). The staff considers these checks to be of a confirmatory nature since they do not relate to known service problems with the capscrews. However, the staff concludes that these checks should be completed by the first refueling outage to ensure that the capscrews will continue to provide adequate service.

On the basis of the above, the staff concludes that the rocker arm capscrews are adequate for nuclear service.

(A.15) Turbocharger

Elliott Model 90G turbochargers for TDI engine application in nuclear service have experienced excessive thrust bearing wear, and there also have been reported failures of nozzle ring components. TDI and the Owners Group established the cause of the thrust bearing wear problem to inadequate lubrication under fast startup conditions. The Owners Group recommended modification of the oil drip system to provide for increased flow toward the engine bearings at all times during engine standby. In addition, the Owners Group recommended modifications to the engine prelube system to incorporate full flow prelubrication by utilizing keepwarm pump flow. These modifications have been installed in the Catawba Unit 2 engines.

Inspection of the engine 2B turbocharger after about 180 hours of service revealed that the thrust bearings were severely worn. The licensee has attributed this problem to lube oil starvation. The licensee stated during phone conversations with the staff that engine 2B experienced a number of trips because of low oil pressure in the lube/oil supply line. These incidents were determined to be the result of a malfunction of the lube/oil pressure-regulating system. The licensee also reviewed the operating logs for engine 2A; the logs do not indicate similar operating problems. The licensee will be required to confirm this information by letter before initial plant criticality is achieved (see Section 8.3.1.1.3(A), "License Conditions").

A possible additional contributing cause was installation of improperly sized lube/oil tubing to replace tubing damaged during engine installation (letter from the licensee dated December 23, 1985). The cross-sectional flow area was reduced by 20% compared with the nominal flow area. The licensee has reported that a check of its records shows that this condition was also unique to engine 2B.

The licensee has not visually inspected the turbocharger thrust bearings for engine 2A. However, the licensee stated in phone conversations with the staff that it has performed rotor float measurements for the engine 2A turbochargers which indicate that the axial clearances are within TDI specifications. The licensee will be required to submit documentation of this inspection before initial criticality is achieved (see Section 8.3.1.1.3(A)). On the basis of these acceptable float measurements and in view of (1) the limited amount of operation with these bearings, (2) the fact that early operating experience with other TDI engines indicates that the above-mentioned lubrication system modifications are effective in minimizing wear rates, and (3) the fact that the anomalous circumstances associated with the wear of the engine 2B thrust bearings were not present for engine 2A, the staff concurs that a visual inspection of the engine 2B thrust bearings is not necessary at this time. This finding is also based on the fact that the licensee will be taking rotor float measurements at each refueling outage to ensure not only that the measurements conform to Elliott specifications, but also to monitor for increasing trends in clearance which could be indicative of bearing degradation. In addition, the bearings will be visually inspected after each 40 automatic, non-prelubricated starts (DR/QR report, Appendix II).

With regard to the nozzle ring components, early operating experience at other plants has included instances in which vanes have broken off because of fatigue, capscrews have failed from fatigue resulting from improper torquing, and capscrew failures have also occurred from intergranular stress corrosion cracking resulting from improper heat treatment. A hub crack has been observed in one nozzle ring which also showed evidence of excessive temperatures.

Many of the problems have occurred with very few operating hours accumulated on the turbochargers. However, no loss of engine availability has occurred as a result of these problems. On the basis of the historical data, inspection reports, and failure analyses, FaAA concludes that the Elliott Model 90G nozzle ring may experience isolated vane failures with accumulated service. However, the vane failures that may occur should not significantly affect turbocharger operation. Capscrew failures are rare events and are not expected to recur, provided that the installation torque is to specification and that manufacturing defects are not present. Thus, FaAA concluded that the current nozzle ring and attachment design is adequate for nuclear standby service (FaAA Report 84-5-7.1, November 1984).

On the basis of their experience, diesel engine expert consultants under contract to the staff's contractor, PNL, believe that there is potential for broken vanes to cause significant damage to the turbine which could affect engine operability (PNL-5600, December 1985). Furthermore, PNL has noted that the turbochargers already operate near the maximum inlet temperature specified by Elliott and that the loss of several blades could increase this temperature further. PNL believes that corrosion and the hot inlet temperatures may have contributed to observed stress corrosion failures of the capscrews and to the cracked hub incident as a result of thermally induced fatigue. PNL has, therefore, recommended that preturbine exhaust temperature be monitored during engine operation to ensure that the temperature specified by Elliott is not exceeded (see Section D.3.2 below).

Finally, the licensee has reported by phone that TDI Service Information Memorandum (SIM) 300 has been implemented for each of the Catawba Unit 2 turbochargers as recommended by the Owners Group. The licensee will be required to confirm this action by letter before intial plant criticality is achieved.

On the basis of the above discussion and subject to implementation of the maintenance and surveillance program discussed in Section D below, the staff concludes that the turbochargers will be adequate for nuclear service.

(B) ENGINE LOAD CAPABILITY

The staff has previously required that the TDI engines be restricted to operation at loads not to exceed a break mean effective pressure (BMEP) of 185 psi pending resolution of technical concerns relating to crankshafts and pistons (References: (1) Staff SER concerning TDI Owners Group Program Plan which was transmitted to J. George, Chairman, TDI Owners Group, Texas Utilities Generating Company, by letter dated August 13, 1984; (2) SSER 4). As discussed earlier in Sections A.5 and A.12, the staff now concludes that the DSRV-16 crankshafts and AE piston skirts are adequate for the full engine load rating (i.e., 7000 kW).

The proposed Technical Specifications for Catawba Unit 2 are consistent with those for Catawba Unit 1 in that surveillance testing is performed at loads to exceed 5600 kW, but not to exceed 5750 kW (185 BMEP).

Although the staff would not object to surveillance testing at rated load, the staff concludes that monthly testing at 5740 kW will be adequate to demonstrate the continued operability of the engines. The staff further observes that 5750 kW exceeds the maximum FSAR emergency service loads which would be automatically connected to the engine during a LOOP/LOCA. In view of the fact that surveillance testing for the Unit 2 engines will be limited to 5750 kW, the staff will verify that a precautionary note has been incorporated into the Catawba Abnormal Procedure for Loss of Normal Power, and to any other applicable plant procedures, to ensure that loads in excess of 5750 kW will not be added unnecessarily to the engines. In addition, the staff will verify that future training with respect to this precautionary note explains the basis for the note and all aspects to be taken into consideration in its application. The staff points out that the basis for the note is to ensure that the engines are run at loads enveloped by the periodic surveillance tests.

(C) STATUS OF DR/QR PROGRAM - PHASE II

Owners Group Phase II recommendations have been documented in plant-specific DR/QR reports and are very similar between plants employing engines of the same model. On the basis of its review of the Phase II DR/QR reports for lead engines at Shoreham (DSR-48 engines) and Comanche Peak (DSRV-16 engines), PNL concluded that implementation of the Owners Group recommendations therein will be effective in improving and ensuring the design adequacy and quality of the engine components at all TDI facilities. PNL has, therefore, recommended that each individual owner faithfully implement all Owners Group recommendations pertaining to Phase II components.

The Owners Group Phase II recommendations have largely been implemented at Catawba Unit 2. However, some Owners Group recommended Phase II quality revalidation (QR) inspections and component modifications remain to be completed. As noted in a previous section, certain QR inspections and component modifications for Phase I components also remain to be completed. On the basis of the actions taken to resolve known problem areas (see Section A above) and implementation of an acceptable and comprehensive maintenance and surveillance program as defined below in Section D, the staff concludes there is adequate basis to defer the aforementioned open items to at least the first refueling outage. The staff will review the licensee's implementation status and schedule relative to these issues before restart from the first refueling outage. Any exception the licensee is planning to take to the Owners Group recommendations (e.g., exceptions in the licensee's letter dated June 21, 1985) should be specifically reviewed and approved by the Owners Group. Approved exceptions should be provided to the NRC staff for information, together with appropriate justification.

(D) ENHANCED MAINTENANCE AND SURVEILLANCE PROGRAM

The engine maintenance and surveillance program will be a key aspect to ensuring the continued operability/reliability of the engines for the life of the plant. This section describes the essential elements of a maintenance and surveillance program which is acceptable to the staff. Such a program should include implementation of (1) TDI and Owners Group recommendations as described in Section D.1 below. In addition, such a program should include additional (1) periodic maintenance actions, (2) operational surveillance actions, and (3) standby maintenance and surveillance actions as identified in Sections D.2, D.3, and D.4 below, respectively.

The staff's contractor, PNL, has concluded that certain DSRV engine components merit special consideration from a maintenance and surveillance standpoint; namely connecting rods, cylinder blocks, cylinder heads, and turbochargers (PNL-5718, December 1985; PNL-5600, December 1985). Accordingly certain elements of the maintenance and surveillance program discussed in this section have also been incorporated as license conditions (see Section 8.3.1.1.3(A) below).

(D.1) TDI and Owners Group Recommendations

Owners Group recommendations concerning engine maintenance and surveillance have been provided as Appendix II to the DR/QR report for Catawba. These recommendations are intended to supplement the existing TDI Instructio Manuals, Service Information Memos (SIMS), and TDI correspondence on specific components to ensure that the engines are adequately maintained for the life of the facility.

In its letter dated April 30, 1985, the licensee has taken a number of exceptions to the Owners Group recommendations in Appendix II to the DR/QR report. However, until these changes have been submitted to and approved by the Owners Group in accordance with the protocol agreed to by the Owners Group members at the Owners Group executive meeting in Dallas on November 22, 1985, the licensee should fully implement the DR/QR Appendix II recommendations as provided to the staff by letter dated November 4, 1985. It is the staff's understanding that a revised Appendix II will be developed by the Owners Group and submitted by the licensee incorporating any changes approved by the Owners Group.

Spot checking by the staff of the Owners Group Appendix II recommendations for Catawba indicate numerous differences relative to the Owners Group Appendix II recommendations for similar V-16 engines at Comanche Peak (lead engine facility), Perry, and Grand Gulf. Examples of differences noted by the staff include the following:

- The Catawba Appendix II is vague about the timing of component inspections (e.g., connecting rods, bushings, and bearing shells; pistons and piston pin assemblies; cam shaft bearings, cylinder heads and valves; etc) associated with "major engine overhauls." The Appendix II recommendations for Comanche Peak, Perry, and Grand Gulf specify that those inspections should be performed at approximately 5-year intervals.

- The Catawba Appendix II specifies that the link pin to link rod clearance check can be performed on a one-time basis. The Appendix II for Comanche Peak and Perry specify that this inspection should be performed at 5-year intervals.

- The Comanche Peak, Perry, and Grand Gulf Appendix II recommendations include gear backlash measurements for the cam gear and crank to lube oil pump gear. These backlash measurements appear to be omitted from the Catawba Appendix II.

On the basis of this spot check, it is possible that other differences may exist between the Catawba Appendix II and the lead engine (Comanche Peak) Appendix II which was reviewed in detail by PNL. No basis for these differences has been provided to the staff. Therefore, except as specifically reviewed and approved by the Owners Group in accordance with the above protocol, the staff concludes that the Catawba Appendix II program should be revised as necessary to be fully consistent with the Comanche Peak Appendix II.

(D.2) Additional Periodic Maintenance Actions Recommended by PNL

This section identifies additional actions which should be incorporated as part of the M/S program for the Catawba Unit 2 diesels. The actions identified in this section are based primarily on the staff's review of M/S recommendations developed by PNL from its review of generic phase I issues (PNL-5600, December 1985). These actions are intended by the staff to supplement instruction manuals supplied by TDI and the M/S recommendations developed by The Owners Group. The NRC staff acknowledges, however, that some of these actions may overlap some Owners Group and TDI recommendations.

(D.2.1) Air Start Capscrews

Capscrews should be installed as recommended by Stone & Webster Co. in its report entitled, "Supplement to the Emergency Diesel Generator Air Start Valve Capscrew Dimension and Stress Analysis," dated April 1984. In addition, the capscrew torque should be checked after the first period of engine operation following air start valve removal or replacement.

(D.2.2) Connecting Rods

The following inspections should be performed during each major (5-year) engine disassembly in addition to those already specified in the DR/QR report.

- If connecting-rod bolt strength was measured ultrasonically during reassembly after the preservice inspection, the lengths of the two pairs of bolts above the connecting rod should be remeasured ultrasonically before the link rod box is disassembled. Alternatively, the breakaway torque should be measured. If bolt tension determined by either method is less than 93% of the value at installation (as recommended by FaAA), the cause should be determined, appropriate corrective action should be taken, and the interval between checks of bolt torque should be reevaluated.

- 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. PNL recommends the wet-fluorescent MT technique (in conjunction with a yoke) rather than a dry particle technique (and direct current prods). All washers used with the bolts should be examined visually for signs of galling or cracking, and should be replaced if damaged.

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

- All of the bolt holes in the rod box should be inspected for thread damage (e.g., galling) or other signs of abnormalities. In addition, the bolt holes subject 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.

- The rack teeth in the serrated joint of the link rod box should be visually inspected for signs of fretting. If fretting has occurred, it should be subject to engineering evaluation for appropriate corrective action.

- During any disassembly that exposes the inside diameter of a rod-eye bushing, the surface of the bushing should be examined with liquid penetrant to verify the continued absence of linear indications in the heavily loaded zone within ±15 degrees of the bottom dead center position.

- Any rod eye not previously examined in accordance with the acceptance criteria recommended by FaAA should be examined using an appropriate nondestructive technique at the first major (5-year) engine disassembly. No indications deeper than 0.04 inch should be allowed.

- The surface contact at the serrated joint and the zero clearance condition between the link pin and the link rod should be checked and verified.

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

(D.2.3) Connecting Rod Bearings

An oil contamination analysis should be performed on a regularly scheduled basis as recommended by the oil supplier. Such a periodic analysis not only can provide an early warning of the deterioration of the bearing shells, but could warn of other developing engine or lubrication problems.

(D.2.4) Crankshafts

- The oil holes and fillets of the three main bearing journals subject to the highest torsional stresses (Nos. 4, 6, 8) shall be examined with fluorescent liquid penetrant and, as necessary, eddy current, during each 5-year major disassembly. The same inspections on oil holes and fillets shall be performed on at least three crankpin journals between journals 3 and 8.

- If an engine is operated in a severely unbalanced condition, it may be necessary to reinspect the oil holes for fatigue cracks. The need for an immediate inspection should be evaluated by the licensee, taking into consideration the particular circumstances of the abnormal operation.

- Hot and cold crankshaft web deflection tests should be performed at 18-month intervals to verify that crankshaft alignment remains within manufacturer's recommendations. The hot measurements should be completed within 15 to 20 minutes of engine shutdown from the 24-hour engine test performed in 18-month intervals in accordance with the plant Technical Specifications.

(D.2.5) Cylinder Blocks

- Cylinder blocks shall be inspected at intervals calculated using the cumulative damage index (CDI) model and using inspection methodologies described by Failure Analysis Associates, Inc., (FaAA) in a report entitled "Design Review of TDI R-4 and RV-4 Series Emergency Diesel Generator Cylinder Blocks" (FaAA-84-9-11), dated December 1984. In addition to these inspections, liquid penetrant inspection of the cylinder liner landing area should be performed any time liners are removed.

- Blocks with known or assumed ligament cracks, as defined in the aforementioned 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 should be used as appropriate to determine the depth of any cracks discovered.

- If inspection reveals cracks in the cylinder block between stud holes of adjacent cylinders, 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.

(D.2.6) Cylinder Heads

The engines shall be rolled over with the airstart system and the cylinder stopcocks open before any planned starts, unless that start occurs within 4 hours of shutdown. The engines shall also be rolled over with the airstart system and 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 cylinders must be determined and any cylinder head that leaks because of a crack shall be replaced. No cylinder heads that contain a through-wall repair that was repaired from one side only shall be used on the engines, except for cylinder heads containing full penetration weld repairs as described on TDI drawing 102718, Revision 0.

(D.2.7) Engine Base

The staff and PNL concur with the Owners Group recommended M/S program for the engine base. However, in addition to cleaning the bearing cap/saddle interface with a solvent whenever the cap/saddle is disassembled, these mating surfaces should also be inspected for surface imperfections that could prevent tight boltup. Imperfections should be removed by stoning, polishing, or replacing parts as needed.

(D.2.8) Fuel Injection Tubing

The staff and PNL concur with Owners Group recommendations concerning high-pressure fuel injection line maintenance and surveillance. In addition, the following actions should be implemented for any future replacement tubing:

- Replacement tubing should be examined over its full length before it is bent, and any tubing with flaws deeper than 0.003 inch should be rejected. This full-length inspection is recommended for replacement tubing because PNL is aware that some intermittent indications have been found in the injection tubing already examined. An eddy-current probe capable of traversing the entire tube bore is suggested for this examination (i.e., the examination would be performed from the inside of the tube rather than the outside, along the entire length).

- Fittings for the injection tubing should be installed and inspected in accordance with the manufacturer's recommendations. The information reviewed by PNL includes no specific instructions for assembling and tightening the fittings. Any nuclear plants that do not already have such instructions should get them from the manufacturer and incorporate them into their maintenance plans.

- Newly installed injection tubing and fittings should be visually inspected for leaks following engine operation. PNL suggests that these inspections be performed only after the engine is shut down, and that the inspector look for wet fittings or other signs of leakage. Inspection of the tubes during engine operation may be hazardous because of the high pressure of the fuel within the tube.

(D.2.9) Jacket Water Pump

The staff and PNL concur with the Owners Group M/S recommendations concerning this component. In addition, the pump impellers should be inspected for signs of cavitation erosion caused by adverse pump motion conditions whenever the pump impellers are exposed to view. This should be done at least once every 5 years.

(D.2.10) Push Rods

All push rod welds should be visually examined during each 5-year major engine disassembly.

(D.2.11) Turbochargers

The staff and PNL concur with Owners Group recommendations in Appendix II of the DR/QR report concerning maintenance and surveillance of the turbocharger with the following modifications or additions:

- Spectrochemical and ferrographic engine oil analysis should be performed quarterly rather than once per outage (as recommended by the Owners Group) to provide early evidence of bearing degradation.

- The nozzle ring components and inlet guide vanes should be visually inspected at each refueling outage (rather than at times of turbocharger disassembly as recommended by FaAA) for missing parts or parts showing distress. If such are noted, the entire ring assembly should be replaced. The frequency of inspections may be relaxed, as appropriate, after the causes of earlier failures are firmly established and corrective actions to prevent recurrence are implemented.

(D.2.12) Special Inspection - EDG 2B, Main Bearing No. 7

The following special inspection of main bearing No. 7 in EDG 2B is being required by the staff to ensure that the kinds of failures observed recently will not reoccur while the engines are in standby nuclear service. The background for this requirement is described in Section E below.

Main bearing No. 7 of EDG 2B shall be disassembled and inspected at each refueling outage, both visually and with liquid penetrant, to verify that the bearings are free of distress. After reassembly, run-in testing shall be performed in accordance with the manufacturer's recommendations.

(D.3) Operational Surveillance Recommendations by PNL

Operational surveillance refers to the parameters to be monitored and/or recorded during engine operation. These typically include temperatures and pressures at key locations in and about the engine, as well as cumulative parameters such as engine hours.

Operational surveillance is necessary to ensure safe and efficient operation of the diesel engine. By monitoring and recording key engine parameters, trends in degradation can be detected, allowing timely preventive maintenance. Trend monitoring may also prevent major engine damage by providing early warning to allow engine shutdown before damage occurs.

PNL has developed a number of recommendations concerning operation surveillance as summarized in Table 8.1 (NUREG-0989, Supplement 3, "Safety Evaluation Report Related to the Operation of River Bend Station, Docket 50-458," August 1985). These PNL recommendations are not intended to supplant the recommendations of TDI or the Owners Group, but rather to identify specific operational surveillance practices that PNL has identified as important. The staff is requiring the licensee to verify that its operational surveillance programs include the items in Table 8.1.

Some of the recommendations in Table 8.1 are discussed in Sections D.3.1 through D.3.6 below:

(D.3.1) Cylinder Exhaust Temperature

Because torsional analyses and torsiograph tests confirm that cylinder imbalance may have a significant effect on crankshaft stresses, appropriate precautions should be taken to prevent sustained engine operation with this condition. Exhaust gas temperatures should be monitored during engine operation to verify that differences between individual cylinder temperatures and the average temperature for all cylinders remain within the range recommended by TDI. In addition, cylinder firing pressures should be measured no less frequently than the interval recommended by TDI. It would also be prudent to analyze the trends of cylinder pressure and temperature measurements to detect changes that might indicate a need for maintenance of fuel injection equipment. Any abnormalities should be corrected at once.

(D.3.2) Preturbine Exhaust Temperature

Continuous monitoring (and hourly logging) of preturbine exhaust temperature is valuable because:

- The individual cylinder exhaust pyrometer reports only a time average of a highly variable function.
- The turbine inlet temperature may be higher than any cylinder exhaust because it is subjected to a continuous stream of hot gases, and also because of possible continued exothermic reactions in the exhaust manifold.
- Blades and nozzle rings could be damaged by temperatures above the manufacturer's limit, which Elliott states is 1200°F.

The staff notes that installation of additional instrumentation may be necessary to monitor exhaust temperatures at the turbine inlet.

(D.3.3) Air Manifold Temperature

The air manifold temperature indicates the effectiveness of the turbocharger aftercooler. Aftercooler efficiency is dependent on water flow rate and temperature and on fouling. Elevated air manifold temperatures reduce maximum load and result in less efficient combustion.

(D.3.4) Fuel Oil Transfer Pump Strainer Differential Pressure

This pressure should be monitored and recorded hourly unless the pump is equipped with an automatic duplex valve and an alarm to protect fuel feed.

(D.3.5) Starting Air Pressure

This pressure must be monitored to ensure sufficient pressure is available for restart at all times.

(D.3.6) Fuel Oil Day-Tank Level

This level must be monitored to ensure fuel availability, even if the tank is equipped with alarms.

(D.4) Standby Surveillance Recommendations by PNL

Standby surveillance is important to ensuring the operability of the diesel engines. The parameters monitored on an engine in standby status are intended to indicate the engine's preparedness to start rapidly and accept load. The two factors that contribute most to this are engine temperature and lubrication. By keeping the engine warm and all oil passages pressurized, the effects of a fast start are minimized. In addition, a ready supply of quality compressed air is required for starting the engines.

PNL has developed a list of standby surveillance items which are summarized in Table 8.2 and which PNL has concluded are important (NUREG-0989, Supplement 3). Again, the information in Table 8.2 is intended to supplement rather than to replace any surveillance procedures developed by the manufacturer, the Owners Group, or by the licensee. The staff notes that some of the items in Table 8.2 are already included in the Owners Group M/S recommendations in Appendix II of the Catawba DR/QR report. The staff is requiring that the licensee verify that the items in Table 8.2 have been incorporated into the standby surveillance program for Catawba Unit 2.

With respect to Table 8.2, two points regarding the keepwarm lube oil filter are important:

- Entrained water or bacteria (in the absence of bactericide use) will tend to plug some filter media (or weaken others), and so would gradually increased pressure drops.

- The continuous keepwarm flow through the filters will (purposely) continuously filter the oil, with gradual buildup of contaminants in the filter media; the material scavenged out helps itself filter even finer particles over time.

Thus, it is important to monitor oil filter pressure drop during standby periods. The changes occur slowly enough that a weekly check is sufficient.

(E) RECENT FAILURES OF NO. 7 BEARING IN ENGINE 2B

Subsequent to the DR/QR inspection of engine 2B which was completed in early November 1985, the subject engine tripped because of a high-temperature indication for main bearing No. 7 during the performance of engine break-in testing. The failure occurred 6 hours into the break-in test at loads between 0 and 60% of the maximum nominal loading.

Inspection revealed the No. 7 bearing had fractured into two major pieces, one small piece, and various missing fragments. The licensee initially attributed this failure to mislocation or damage during initial installation at the factory, and installed a new bearing. Again, a high bearing temperature shutdown occurred, at approximately 90 seconds into the initial break-in run. Subsequent inspection revealed that the new No. 7 bearing had also failed. A major crack had developed, although it had not yet progressed to the point of complete fracture.

Both the upper and lower bearing shells from both failures were observed by the NRC staff and two expert diesel engine consultants under contract to the staff. Both bearings exhibited areas of wear and other deterioration of the babbetted surfaces, various scores through the babbett, and (especially in the lower shell of the second failure) evidence of overheating, as expressed in blisters formed under the babbett. In the fractured lower shell, some of the broken surfaces were darker than other such areas, inferring they had been exposed to oil and oxidation for a longer period than the lighter colored areas, thus indicating that failure progressed over a prolonged period.

There was some wear along both side edges of the lower first shell, where the loosened segments apparently moved axially sufficiently to rub against the adjacent crank throws; one area of wear was quite pronounced.

Various other visible indications also existed, on both the wearing surfaces and other edges, and the back of the shells. Of particular note were signs of distress in the areas of the "keyways" at the ends of the lower bearing shells. These are machined, partly circular "indentations" in both upper and lower shells. In the upper shells they provide accommodations to circular "keys" (thick, machined "washers") which, bolted into the appropriate counterbored keyways of the bearing caps, serve to hold the upper shell in place within the cap as that assembly is lowered (shell down) over the shaft journal and onto the bearing saddle of the base. Two mating keyways exist in the base saddle areas and the lower bearing shells, to accommodate the keys attached to the cap. Clearance between the keys and keyways is reportedly some 0.020 inch on the diameter, resulting in some degree of loose fit. During a meeting with the staff at Catawba on December 30, 1985, the licensee reported the following:

- A hot deflection test had been performed before the DR/QR inspection in October 1985, and a cold deflection test was performed immediately afterward, indicating that the crankshaft was in proper alignment.
- Extensive dimensional, visual, and nondestructive inspections of the engine base (particularly around the No. 7 bearing saddle), bearing cap, and crankshaft which were performed after the second failure, did not reveal any dimensional anomalies or evidence of distress that might explain the failures. These inspections were performed with the crankshaft in place.

- Bearing No. 7 was not inspected at the recent DR/QR inspection, but bearings No. 4, 6, and 8 were examined. Scoring was determined to be moderate; but, as a precaution, bearings No. 4 and 6 were replaced and No. 8 was reinstalled. The licensee reported that conditions of bearing and journal surfaces appeared progressively worse at the subsequent first and second failures.

- After the first failure the lube oil filters, strainers and sumptank were inspected and appropriately cleaned. Fresh oil was installed. The old oil was tested; there were no indicative findings. Nothing significant was found on filters or strainers.

- Gritty contaminants - apparently from some field pipe fabrication - was found in the lube oil piping or strainer plenum, but in a section not used since the engines were turned over to the plant operating staff by the plant construction staff. Whether the same condition also existed in the alternate filter and piping used throughout operations to date is unkown at present. The recovered material is still under examination; but it appeared to be metallic, of 40-80 micron size, some is sharp edged and some is rounded.

- Pistons, rods, and related running gear for the No. 6, 7, and 8 (left and right bank) cylinders were inspected. No deleterious indications were found, except for modest amounts of aluminum flakes embedded in the No. 7 connecting rod bearing (as might be expected).

- The licensee has removed and either reinstalled or replaced numerous main bearings on the four TDI EDGs at Catawba in the course of the various standard and special inspections and maintenance efforts relative to the TDI operability/reliability concerns of the past two years. No other bearings have failed or given signs of distress (as is known to date).

- There have been no reports of similar failures/problems with TDI main bearings at other nuclear plants.

On the basis of the evidence, the licensee and its consultants concluded that both bearing failures resulted from improper alignment upon installation of the lower bearing shells, which led to some binding and disrupted oil film. The quicker failure of the second bearing appeared to them to indicate greater misalignment, possibly aggravated by residual problems (on the journal and/or in the oil system) from the first failure.

To minimize the potential for again installing the bearings in a misaligned configuration, the lower bearing shell will be installed while the crankshaft is lifted to relieve the weight that would normally be placed on the bearing while it is rolled into place. This will serve to ease the insertion of the lower bearing shell and will allow its axial movement as needed to ensure proper alignment. Proper alignment of the lower shell will be verified by placing a dowel pin in each of the two base and bearing shell keyways and confirming via a "blueing" process that the lower bearing shell is properly positioned.

To ensure that these measures are effective in preventing further bearing failures, the licensee agreed during the December 30, 1985, meeting with the staff to perform additional confirmatory testing and inspection to include the following:

(1) Bearing No. 7 will be disassembled and inspected after running the engine for an initial 1-hour period.

(2) A hot web deflection check will be performed immediately following completion of "run-in" testing.

(3) A total of 100 hours shall be accumulated on the new No. 7 bearing, following which the bearing will be removed from the engine and verified to be in acceptable condition by visual and liquid penetrant (LP) inspection.

Evaluation

TDI and the licensee have not been able to explain how two successive bearings could be installed in a misaligned position. The staff finds that improper installation practice is not likely to be a common causal factor since one of the two bearings was installed by TDI at the factory and the other by the licensee's personnel at the site; furthermore, no other failures of this type have been reported for other TDI engines in nuclear service.

Another possibility is that there is a dimensional or some other physical anomaly in the engine base, bearing cap, or perhaps crankshaft, which has escaped detection during the inspections completed to date. As an example, one of the staff consultants concluded that an erroneous machining of the keyways may be the most probable root cause resulting in an interference fit of the keys and the shell keyways, with consequential distortion and stressing of the shell, a breakdown of lubrication, overheating, and rapid failure. It should be noted that the inspections performed by the licensee subsequent to the bearing failures were performed without removing the crankshaft. The NRC consultant noted that it is difficult to accurately ascertain the relevant dimensions without removing the crankshaft.

Another NRC consultant involved in reviewing the bearing failures has suggested another possible failure mechanism; namely, that dirt in the engine may have initiated the first bearing failure. This finding was based on the consultant's observations of the wear and score marks on the bearing and crankshaft journal surfaces and the consultant's experience that an alignment problem would have caused the bearing to fail much sooner. A TDI representative, in discussions with the NRC staff, agreed with this latter point stating that it is TDI's experience that in cases of misalignment, bearing failures are likely to occur in a few minutes (as was the case for the second failure) rather than after many hours as was the case for the first failure. This second NRC staff consultant believes, however, that the second failure probably resulted from misalignment and possibly from inadequate cleaning of the crankshaft journal following the first failure. This consultant has speculated that the bearing misalignment could have resulted from physical damage to the bearing (such as could occur had the bearing been dropped) before it was installed in the engine.

On the basis of its review and consultation with its consultants, the staff has concluded that there is considerable uncertainty about what caused the bearing failures, particularly the first failure. The staff believes that the careful installation of the bearing in the manner described earlier will minimize the potential for bearing misalignment caused by a minor dimensional or other physical anomaly or by improper installation. In addition, the extensive flushing and cleaning of the lube oil system will minimize the potential for foreign matter in the oil to cause bearing damage. However, the effectiveness of these corrective measures will be proved by the 100-hour confirmatory endurance test of the engine.

The staff concludes that successful completion of the confirmatory test without significant bearing distress will ensure that the licensee's actions have been effective in precluding the rapid and/or highly premature bearing failures of the kind that occurred previously. However, in view of the present uncertainty regarding the exact cause of the earlier failures, the staff also concludes that the No. 7 bearing should be disassembled and carefully inspected at each plant refueling outage to ensure that the No. 7 bearing will continue to provide adequate service for the plant (see Section D.2.12 above).

8.3.1.1.3 Conclusions

This SSER precedes issuance of the staff's evaluation regarding final technical resolution of generic TDI diesel generator issues. That report will address the Owners Group program and the Owners Group findings and recommendations stemming from that program. That generic SER is expected to be issued in early 1986. However, the staff's contractor, PNL, has completed its review of this matter and documented its findings in PNL reports 5444, 5600, and 5718. The staff worked closely with PNL during preparation of these reports. Therefore, the staff's conclusions in the forthcoming generic safety evaluation report are not expected to differ significantly from the findings and recommendations reached by PNL.

On the basis of the staff's review of the aforementioned PNL findings and the licensee's actions to implement the Owners Group recommendations, the staff concludes that all significant TDI issues warranting priority attention as a basis for issuing an operating license have been adequately resolved. Consequently, the NRC 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 conditions, procedures, and programs detailed in Sections A through D which follow.

(A) License Conditions

The licensee shall comply with the following requirements related to the TDI diesel engines:

(1) Changes to the maintenance and surveillance program for the TDI diesel engines, as identified in Section 8.3.1.1.2(D) of SSER 5 shall be subject to the provisions of 10 CFR 50.59.

(2) Connecting-rod assemblies shall be subjected to the following inspections at each major engine disassembly (approximately every 5 years):

- The clearance between the link pin and the link rod should be examined. This dimension must be zero when the specified bolt torque is applied.

- The surfaces of the rack teeth should be inspected for signs of fretting. If fretting has occurred, it should be subject to an engineering evaluation for appropriate corrective action. The mating surfaces should also be examined to ensure that the percentage of contact meets manufacturer's recommendations.

- 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.

- If connecting-rod bolt stretch was measured ultrasonically during reassembly following the preservice inspection, the lengths of the two pairs of bolts above the connecting rod should be remeasured ultrasonically before the link rod box is disassembled. Alternatively, the breakway torque should be measured. If bolt tension determined by either method 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 torque should be reevaluated.

- 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 replaced if damaged.

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

- 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 subject 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.

(3a) Cylinder blocks shall be inspected at intervals calculated using the cumulative damage index (CDI) model and using inspection methodologies described by Failure Analysis Associates, Inc., (FaAA) in a report entitled "Design Review of TDI R-4 and RV-4 Series Emergency Diesel Generator Cylinder Blocks" (FaAA-84-9-11), December 1984. Liquid penetrant inspection of the cylinder liner landing area should be performed any time liners are removed. If inspection reveals cracks in the cylinder block between stud holes of adjacent cylinders, 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.

(3b) Prior to restart from the first refueling outage, the licensee shall submit its cumulative damage analysis performed in accordance with FaAA report No. FaAA-84-9-11 dated December 1984, which verifies the acceptability of the "as built" dimensions of the Catawba Unit 2 cylinder blocks. Alternatively, the block dimensions should be modified as necessary to meet the latest TDI specifications.

(4) The engines shall be rolled over with the airstart system and the cylinder stopcocks open prior to any planned starts, unless that start occurs within 4 hours of a shutdown. The engines shall also be rolled over with the airstart system and 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 prior to 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 cylinders must be determined and any cylinder head which leaks due to a crack shall be replaced. No cylinder heads that contain a through-wall weld repair where the repair was performed from one side only shall be used on the engines except for cylinder heads containing full penetration weld repairs as described in TDI drawing 102718, Revision 0.

(5) Periodic inspections of the turbochargers shall include the following:

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

- 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 whether a trend exists. Any such trends shall be evaluated by the licensee to determine a need for further inspection or corrective action.

- 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.

- The nozzle ring components and inlet guide vanes should be visually inspected at each refueling outage for missing parts or parts showing distress. If such are noted, the entire ring assembly should be replaced.

- Pre-turbine exhaust temperature shall be monitored during engine operation to ensure that the manufacturer's temperature limit is not exceeded.

(6) Main bearing No. 7 of emergency diesel generator 2B shall be disassembled and inspected at each refueling outage, both visually and with liquid

penetrant, to verify that the bearings are free of distress. Subsequent to reassembly, run-in testing shall be performed in accordance with manufacturer's recommendations.

(7) Operation beyond the first refueling outage shall require staff approval based on the staff's final review of the Owners Group generic findings and of the overall implementation status of Owners Group recommendations at Catawba Unit 2. This will include staff review of implementation status relative to open items identified in Sections 8.3.1.1.2(A) and 8.3.1.1.2(C) of SSER 5.

(8) The following confirmatory information shall be submitted to the NRC staff prior to initial plant criticality.

(a) Verify that each engine base has been fabricated from normal class 40 gray iron which is free of Widmanstaetten graphite microstructure

(b) Submit details concerning nature and cause of indication found on one rocker arm capscrew from engine 2B. This information should address whether the indication is service induced or whether it occurred as a result of fabrication or installation.

(c) Submit evaluation of causal factors leading to wear of turbocharger thrust bearings in engine 2B. Confirm that these causal factors have been found to be unique to the engine 2B turbocharger and justify how this conclusion was reached.

(d) Confirm that rotor float measurements have been conducted for both engine 2A turbochargers and that these measurements are acceptable per the TDI specifications.

(e) Verify implementation of TDI Service Information Memorandum (SIM) 300.

(9) The No. 7 main bearing from engine 2B shall be disassembled and inspected, both visually and with liquid penetrant, following a 100-hour endurance test of this bearing to verify that the bearing continues to be in adequate condition and free of any significant distress. The staff should be immediately notified of any adverse findings as a result of this inspection. A report shall be submitted to the NRC staff prior to initial plant criticality which documents in detail (1) the circumstances of the earlier failures of the No. 7 bearing, (2) the investigations, analyses, and inspections conducted to establish the cause of these failures, (3) the findings from these efforts, (4) the corrective actions taken, and (5) a description and the results of the 100-hour confirmatory test/inspection of the No. 7 bearing.

(B) <u>Operating Procedures</u>

In order to avoid the 4th order critical speed at 450 rpm, engine operating and emergency procedures should be modified as necessary to provide guidance against steady operation at speeds more than a few rpm below 450 rpm.

Engine operating and emergency procedures and training should caution the operators against operating the engines in excess of 5750 kW, since surveillance testing is not periodically conducted above this load (see Section 8.3.1.1.2(B)).

The NRC staff should verify compliance with these actions before initial plant criticality.

(C) Maintenance and Surveillance Program

The licensee shall implement a maintenance and surveillance program to ensure that the engines will remain in an operable/reliable condition for the life of the facility. The minimum elements of an acceptable maintenance and surveillance program are as defined in Section 8.3.1.1.2(D) of SSER 5.

(D) Completion of the Owners Group Program

As discussed in Sections 8.3.1.1.2(A) and (C) of this SSER, certain quality revalidation (QR) inspections and component modifications recommended by the Owners Group have not yet been implemented for Catawba Unit 2. On the basis of actions taken to resolve known problems areas (see Section 8.3.1.1.2(A)) and implementation of an acceptable maintenance and surveillance program as defined in Section 8.3.1.1.2(D), the staff concludes that there is adequate basis to defer the aforementioned open items to at least the first refueling outage. The staff will review the licensee's implementation status and schedule relative to these issues before restart from the first refueling outage. Any exception the licensee is planning to take to the Owners Group recommendations (e.g., exceptions in the licensee's letter dated June 21, 1985) should be specifically reviewed and approved by the Owners Group. Approved exceptions should be provided to the NRC staff for information, together with appropriate justification.

Table 8.1 Operational surveillance recommendations

Item	PNL recommendation
Lube oil engine inlet pressure	Log hourly
Lube oil to turbocharger pressure	Log hourly
Lube oil filter differential pressure	Log hourly
Lube oil temperature (inlet and outlet)	Log hourly
Fuel oil to engine pressure	Log hourly
Fuel oil filter differential pressure	Log hourly
Air manifold pressure	Log hourly
Air manifold temperature	Log hourly
Jacket water pressure (inlet)	Log hourly
Jacket water temperature (inlet and outlet)	Log hourly
Crankcase vacuum	Log hourly
Exhaust temperature of all cylinders	Log hourly
Exhaust temperature at turbine inlet (preturbine)	Log hourly
Hour meter	Log hourly
Generator load	Log hourly
Fuel oil transfer pump strainer differential pressure	Log hourly unless strainer is auto/duplexed and alarmed
Starting air pressure	Check hourly
Fuel oil day-tank level	Check hourly or as required per tank size
Compressed air system	Drain condensate every 4 hours of engine operation
Leaks	Visually inspect engine and piping monthly and after 24 hours of operation

Table 8.2 Standby surveillance recommendations

Item	PNL recommendation
Starting air pressure	Check visually every 8 hours; log every 24 hours
Lube oil temperature (inlet and outlet)	Check visually every 8 hours; log every 24 hours
Jacket water temperature (inlet and outlet)	Check visually every 8 hours; log every 24 hours
Lube oil sump level	Check visually every 8 hours; log every ?4 hours
Fuel oil day-tank level	Check visually every 8 hours; log every 24 hours
Annunciator test	Test every 8 hours
Alarm clear	Check daily
Compressed air trap operation	Check daily
Governor oil level	Check daily
Leaks on engine and auxiliary equipment	Inspect daily; more detailed inspection monthly
Operational freedom of combustion air butterfly valve and cylinder	Check monthly
Keepwarm oil filter differential pressure	Check weekly
Jacket water pH, conductivity, and corrosion inhibitor	Test monthly
Air start distributor filter	Check monthly
Air start admission valve strainer	Check quarterly
Lube cil	Analyze monthly

9 AUXILIARY SYSTEMS

9.5 Other Auxiliary Systems

9.5.1 Fire Protection Program

9.5.1.1 Introduction

On April 15-19, 1985, NRC Region II personnel conducted an onsite inspection of fire protection features at Catawba Nuclear Station, Units 1 and 2, including implementation of the plant safe shutdown guidance provided in Positions C.5.b and C.5.c of SRP Section 9.5.1. The results of this inspection are detailed in NRC Inspection Report No. 50-413/84-15.

It was noted during this inspection that the structural steel which supports protected cables in the auxiliary feedwater pump room area was not fire protected with a 1-hour fire resistive material. It was agreed during the inspection that the licensee's technical justification for not wrapping the cable tray supports would be submitted to the staff for review. This information was submitted by letter dated May 31, 1985.

Dicussion

The licensee's analysis of the structural adequacy of the cable tray support members was based on the maximum potential fire severity for a postulated fire in the auxiliary feedwater pump room. To determine this "worst case" fire, the licensee quantified the in situ and transient combustibles. The resulting fire load was then compared to the American Society for Testing and Materials (ASTM) E119 time-temperature curve. If the combustibles were totally consumed, the resulting fire would be of 4.2 minutes' duration. This time was determined to be less than the time required to cause failure of the tray supports (5 minutes at an ambient temperature of 1100°F). The licensee, therefore, concluded that the supports did not require additional protection.

Evaluation

The staff's principal concern was that in the event a fire of significant magnitude occurred, the tray supports would fail, resulting in damage to the fire-rated barrier which protects shutdown-related cables in the tray. However, this room is provided with a fire detection system that annunciates automatically in the control room. This ensures that a fire would be detected in its formative stages before significant fire propagation or ambient temperature rise occurred. The plant fire brigade would then be dispatched to put out the fire using manual fire fighting equipment. If the fire spread rapidly before the brigade arrived, the automatic sprinkler system in the room would actuate. This would control the fire, reduce room temperature, and protect the cable tray and its supports from further damage. If the fire brigade did not extinguish the fire promptly and if the sprinkler system did not function, the licensee's analysis demonstrates that the tray support would not fail, on the basis of the stated assumptions.

Conclusion

The staff concludes that the supports for the protected tray in the auxiliary feedwater pump room do not require additional protection. The staff considers this issue closed.

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 (Specific)

(3) Internal Corrosion Protection for the Fuel Oil Storage Tanks

By letters dated October 2 and November 21, 1984, the licensee provided additional data and justification for not providing internal corrosion protection in the diesel generator fuel oil storage tanks.

In the November 21, 1984, letter, the licensee committed to perform ultrasonic tank-wall thickness measurements at the 10-year internal tank cleaning required by the plant Technical Specifications. By letter dated December 21, 1984, the licensee changed the above commitment to a proposed surveillance requirement to be included in the plant Technical Specifications. The staff has reviewed the licensee's data, the justification for not providing corrosion protection, and the proposed surveillance requirement, together with the fuel oil system design described in the SER. The staff agrees with the licensee that internal corrosion protection will not be required at Catawba. The staff has incorporated the licensee's proposed surveillance requirement in the plant Technical Specifications.

Therefore, the staff finds that the Catawba fuel oil system design is acceptable. On the basis of the above evaluation, license condition 18 in the SER has been removed.

*By letter dated January 17, 1985, the staff transmitted Section 9.5.4.2(3) to the licensee together with the full-power operating license for Unit 1.

13 CONDUCT OF OPERATIONS

13.1 Organizational Structure of Applicant

13.1.2 Operating Organization

13.1.2.3 Shift Crew Composition

Operating Experience on Shift

License condition 10 of Facility Operating License NPF-35 (license condition 44 of SSER), issued to Duke Power Company for operation of Catawba Unit 1, required that the licensee retain a shift advisor on each shift at the plant until such time as at least one senior operator on the shift had attained the experience levels specified by Generic Letter 84-16. In addition, license condition 10 required the licensee to notify the NRC at least 30 days before the proposed release of shift advisors from further service.

By letter dated March 1, 1985, the licensee advised the staff that by April 17, 1985, shift personnel would have attained the required experience levels and that use of shift advisors would be discontinued on that date.

NRC Inspection Report Nos. 50-413/85-14 and 50-413/85-11, issued on May 30, 1985, reported that the NRC staff had reviewed the plant records for operating experience and had determined that all senior operators on shift at Catawba Unit 1 had achieved the minimum experience levels as specified in Generic Letter 84-16. On the basis of this review, the staff concluded that license condition 10 has been satisfied.

The staff reviewed the Catawba Unit 1 operating history when it received the March 1, 1985, letter from the licensee, and concluded that it was likely the licensee had satisfied license condition 10. On the basis of that earlier review, and the corroboration offered in Inspection Report Nos. 50-413/85-14 and 50-413/85-11, the staff concluded that license condition 10 was satisfied.

A question now arises concerning the need for a license condition for Catawba Unit 2 similar to license condition 10 imposed on Catawba Unit 1. For reasons noted below, the staff sees no need for such a license condition.

In a meeting with NRC Region II on November 15, 1985, regarding the state of readiness for operation of Catawba Unit 2, the licensee reported that Catawba was operating on a 5-shift, 12-hour-rotation schedule. For two-unit operation, the Technical Specifications require one shift supervisor (senior reactor operator (SRO)) on each shift and one additional SRO in the control room. Against this requirement, the licensee is staffing each operating shift with one shift supervisor (SRO) and two unit supervisor/control room SROs, thus providing one more senior licensed staff member on shift than the Technical Specifications require. A total of 7 shift supervisors and 11 unit supervisor/control room SROs are available for assignment to the operating shifts. With the exception of one shift supervisor who currently is licensed for Unit 1 only (pending reexamination), all SROs are licensed on both Units 1 and 2. All shift supervisors now have more than 13 months of hot operating experience and, with one exception, all unit supervisors/control room SROs have more than 7 months of hot operating experience.

Although not required by Generic Letter 84-16, the staff notes that during the period of Unit 1 operation, other shift personnel also have acquired considerable experience in plant operations.

Because all the senior operators, with one exception, have achieved experience levels considerably in excess of the minimum established by Generic Letter 84-16, and because these operators are dually licensed for both Units 1 and 2, the staff finds no need for a license condition for the Unit 2 license that addresses operator experience levels. The staff concludes that such a license condition should not be made a part of the Unit 2 operating license. Thus license condition 44 of SSER 4 is resolved for Units 1 and 2.

13.3 Emergency Preparedness

The staff reviewed the licensee's emergency plan and revisions thereto, and reported the results of the review in previous SER supplements. The Federal Emergency Management Agency's (FEMA's) review of the offsite plans and the full-participation exercise was reported in Supplement 4 (December 1984). Section 13.3 of Supplement 4 also identified the license conditions and confirmatory items as imposed by the Atomic Safety and Licensing Board in its Partial Initial Decision (PID) dated September 18, 1984. These items were required to be completed before June 4, 1985. This fifth supplement provides the staff's determination that the Board's conditions have been met. The Board's conditions are:

(1) The licensee's public information brochure shall state that high levels of radiation are harmful to health and may be life threatening. Such statements shall be contained within that portion of the brochure that deals with actions to be taken in the event of an emergency.

(2) The warning signs and decals shall specify the types of emergencies they cover, including nuclear emergencies.

(3) The warning signs and decals shall notify transients as to where they can obtain local emergency information (in accordance with NUREG-06'4, II G.2.).

(4) The licensee's emergency plans shall reflect the kinds of locations within the plume exposure emergency planning zone (EPZ) where the warning signs and decals and emergency response information will be placed, and the procedures employed to assure that sufficient numbers are being distributed to effectively reach transients, and that the plans be implemented.

(5) The licensee shall ensure that comprehensive plans exist for early notification to Carowinds amusement park of a radiological emergency at Catawba and for evacuation of Carowinds. The plan shall describe the responsibilities of the emergency response organizations of Mecklenburg

and York Counties and provide for the coordination of their efforts among themselves and with Carowinds officials. The plans shall provide for immediate notification of patrons and staff of Carowinds at the time of the precautionary closing of the park, of the cause of the emergency. The means to implement the plans shall be made available.

In addition to the above license conditions, the Board directed the licensee to (1) confirm to FEMA and the NRC staff that FEMA's finding, arising from the February 1984 exercise, that more Gaston County personnel be trained in monitoring and decontamination procedures has been addressed and (2) obtain changes to the South Carolina Emergency Plan that will show the role and responsibilities of the Division of Public Safety in the Office of the Governor of South Carolina in ordering evacuations along with the identification of key individuals by title, and provide copies to FEMA and the NRC staff. The staff requested the assistance of FEMA in working with the licensee and State and local government authorities to verify that the above license conditions have been met and the Board-directed actions have been satisfactorily completed.

On April 30 and May 15, 1985, FEMA provided findings on the licensee's March 18, 1985 submittal in response to the Board Order of September 18, 1984 (Appendices I and J, respectively). FEMA concluded that the emergency preparedness issues as specified in the Board Order have been satisfactorily resolved. The NRC staff has reviewed the FEMA analysis and concludes that the Board's imposed license conditions have been met, and the two confirmatory items have been satisfactorily completed.

Offsite Emergency Planning Medical Services

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

*This section has been extended to cover both onsite and offsite emergency planning.

dangerous levels of radiation as well as the slow development of adverse reactions to overexposure. See "Emergency Planning; Statement of Policy," 50 FR 20892, May 21, 1985.

Consistent with the foregoing Statement of Policy, the applicant has, by letter dated October 15, 1985, confirmed that the emergency plans of the involved offsite response jurisdictions contain a list of medical service facilities. The existence of such a list in the pertinent plans has also been confirmed by FEMA. Furthermore, the applicant has committed to fully comply with the Commission's response to the Court's remand.

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

Federal Emergency Management Agency 44 CFR 350 Finding on Offsite Plans and Preparedness

The FEMA interim finding of July 22, 1984, was discussed on page 13-5 of SSER 4, December 1984. In a memorandum dated October 8, 1985 (Appendix M in this SSER), FEMA provided its final finding and determination in accordance with 44 CFR 350. The memorandum stated in part that

> Subject to the condition stated below, the South Carolina and North Carolina State and local plans and preparedness for the Catawba Nuclear Station are adequate to protect the health and safety of the public in that there is reasonable assurance that the appropriate protective measures can be taken in the event of a radiological emergency. However, while there is an alerting and notification (ANS) system in place and operational, this approval is conditioned on FEMA's verification of the ANS in accordance with the criteria in NUREG-0654/FEMA-REP-2, Rev. 1, Appendix 3 and in FEMA-43, "Standard Guide for the Evaluation of Alert and Notification Systems for the Nuclear Power Plants."

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

13.6 Physical Security Plan

13.6.1 General

The licensee has filed with the NRC for Catawba Unit 2 the following security plans, which have since been amended: "Catawba Nuclear Station Physical Security Plan," "Catawba Nuclear Station Contingency Plan," and the "Catawba Nuclear Station Guard Training and Qualification Plan."

This supplement (SSER 5) summarizes how the licensee has provided for meeting the requirements of 10 CFR 73. The staff's evaluation consists of a basic analysis that is available for public review, a protected appendix that is not available for public review, and a protected response force size worksheet, also not available to the public.

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 licensee against radiological sabotage at the Catawba Nuclear Station 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 Physical Security Organization

To satisfy the requirements of 10 CFR 73.55(b), the licensee has provided a physical security organization that includes a security shift supervisor who is on site at all times and has the authority to direct the physical protection activities. To implement the commitments made in the physical security, guard training and qualification plan, and the safeguards contingency plan, 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 "Catawba Nuclear Station 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 where the individual is trained, equipped, and qualified to perform the assigned duty in accordance with the approved guard training and qualification plan.

13.6.3 Physical Barriers

In meeting the requirements of 10 CFR 73.55(c), the licensee has provided a protected area barrier that meets the definition of 10 CFR 73.2(f)(1). An isolation zone of at least 20 feet, designed 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 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.

The protected area is patrolled at random intervals to detect the presence of unauthorized persons, vehicles, and materials.

13.6.3.1 Identification of Vital Areas

The licensee has proposed an alternative strategy in lieu of protecting as vital the equipment prescribed in Review Guideline 17 (i.e., protecting the elements of the safe shutdown system).

Primary reliance for ultimate safe shutdown is placed on a standby shutdown facility (SSF), a hardened, free-standing structure equipped with independent emergency power, reactor shutdown controls, and a separate signal and control wire distribution system.

During the licensing of Catawba Unit 1, a special staff team reviewed the protection strategy for the safe shutdown system (SSS). Headquarters staff members concluded that protecting the SSS elements as vital equipment satisfied current requirements. Region II personnel determined that additional equipment should be protected, and these items were added by the licensee to the security plan as security access areas. The Catawba Unit 2 program is identical and, accordingly, the staff finds it acceptable.

The appendix discusses the licensee'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 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 in the appendix, the staff has concluded that the licensee's program for identifying and protecting 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 they are found to be necessary.

13.6.4 Access Requirements

In accordance with 10 CFR 73.55(d), all points of personnel and vehicle access 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 for licensee-designated vehicles, are controlled by escorts. Licensee-designated vehicles are limited to onsite station functions and remain in the protected area except for operational maintenance, repair, security, and emergency purposes. Positive control over these vehicles is maintained by personnel authorized to use the vehicles, or by the escort personnel.

The photobadge/keycard system, utilizing encoded information, identifies individuals who are authorized unescorted access to protected and vitals areas and is used to control access to these areas. Individuals not authorized unescorted access are issued badges without photos, which indicate an escort is required. Access authorizations are limited to those individuals who need access in order to perform their duties.

Unoccupied vital areas are locked and protected with alarms. 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 protected with alarms. Keys, locks, combinations, and related equipment are changed annually. In addition, when an individual's access authorization has been terminated because of lack of reliability or trustworthiness, or poor work performance, the keys, locks, combinations, and related equipment to which that person had access are changed.

13.6.5 Detection Aids

In satisfying the requirements of 10 CFR 73.55(e), the licensee 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, ceiling, doors, and windows are bullet resistant. The alarm stations are located and designed so that a single act cannot interdict the capability of calling for assistance or responding to alarms. No other functions or duties that would interfere with its alarm response function are performed in the central alarm station.

The intrusion detection systems' 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.

13.6.6 Communications

As required in 10 CFR 73.55(f), the licensee 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 nonportable communication links, except the conventional telephone system, are provided with an uninterruptible emergency power source.

13.6.7 Test and Maintenance Requirements

In meeting the requirements of 10 CFR 73.55(g), the licensee has established a program for testing and maintaining 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 to otherwise operate will be compensated for by appropriate compensatory measures as defined in the "Catawba Nuclear Station 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 during which they are used. Such testing will be conducted at least once every 7 days. Systems for onsite communications are tested at the beginning of each security shift. Systems for 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, which focus 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 licensee's quality assurance and management staffs prepare a report documenting their findings and recommendations and submit it to the licensee for review and necessary action.

13.6.8 Response Requirements

In meeting the requirements of 10 CFR 73.55(h), the licensee has provided for armed responders immediately available for response duties on all shifts consistent with the requirements of the regulations. In addition, liaison with local law enforcement authorities to provide additional response support if a security-related event should occur has been established and documented.

The licensee'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-related events that could initiate a radiological sabotage event and identifies the licensee'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 would include (1) the neutralization of the existing threat by requiring the response force members to interpose themselves between the adversary and the objective, (2) instructions to use force commensurate with that used by the adversary, and (3) authority to request sufficient assistance from the local law enforcement authorities to maintain control over the situation.

13.6.9 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 licensee has provided for an employee screening program. Personnel who successfully complete the employee screening program or its equivalent may be granted unescorted access to protected and vital areas at the Catawba site. All other personnel requiring access to the site are escorted by persons who are authorized and trained for escort duties and who have successfully completed the employee screening program. The employee screening program is based on 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 recognizes a certain period of trustworthy service with the utility or contractor as being equivalent to the overall employee screening program. The staff has reviewed the licensee's screening program against the accepted industry standards (American National Standards Institute Standard N18.17, 1973) and has determined that the licensee's program is acceptable.

14 INITIAL TEST PROGRAM

(a) Discrepancies in the Test Program

In a letter dated July 12, 1985, the licensee notified the staff that the Catawba test program was complete with the exception of four testing discrepancies. Catawba Facility Operating License NPF-35 has license condition 3 which, among other things, is intended to prevent extended operation with untested or partially tested systems important to safety.

The staff reviewed the test discrepancies in context with the intent of license condition 3. These testing discrepancies are:

(1) Steady state vibration measurements have not been performed on (a) spent fuel cooling system, train B; (b) boron thermal regeneration system; and (c) boric acid transfer pump 1B and associated piping. All measurements are to be performed at an appropriate later time.

(2) Regarding the unit load steady state test, the steam generator pressures exceeded the predicted values, but are within system design pressures.

(3) Regarding the secondary systems functional tests, vacuum in main condenser C is less than expected.

(4) Regarding the boron thermal regeneration system functional test, system modification and testing are to be done at a later time. This system is not safety related and the licensee's letter states that its use will be administratively precluded until modification and testing can be completed.

Although these test deficiencies were generated from the initial test program, the intent of license condition 3 pertains to systems important to safety and none of these discrepancies pose a safety concern if proper administrative control and tracking are maintained. The staff agrees with the licensee's evaluation that these items have no impact on the continued safe operation of Catawba Unit 1, and if these are the only test program deficiencies, the test program should be considered complete.

Tracking for disposition and/or completion of these deficiencies should be followed by NRC Region II staff in accordance with the standard enforcement and inspection procedures for plant inspection.

(b) Update of the Initial Test Program

Since SSER 4 was issued in December 1984, the licensee made several modifications to the initial test program for Unit 2. The staff has reviewed these modifications through FSAR Revision 14. Many of the modifications were minor, e.g., typographical, editorial clarification, reference to updated design specifications, and reference to a new, revised standard. Following is a discussion of the more significant modifications.

The licensee revised the test abstract for the below bank rod test (Table 14.2.12-2, page 5) to indicate that it would not be performed on Unit 2. The purpose of this test was to ensure that observed hot channel factors are consistent with assumptions used in the analysis of a dropped rod event. Because the data collected during this test on other units indicate that the results are consistent from plant to plant, this test is no longer required, unless a significant change in core design is involved. In addition, this test was performed on Catawba Unit 1, and the data from that test support the findings from other plants' tests. Therefore, the staff concludes that deletion of this test from the Catawba Unit 2 test program is acceptable.

The licensee also indicated that the feedwater temperature variation test (Table 14.2.12-2, page 31) would not be performed on Unit 2. The purpose of this test was to determine the effect of a reduction in feedwater temperature caused by opening a feedwater heater train bypass valve. The plant response is determined by the magnitude of the change in feedwater temperature and by the action of automatic control systems. Because the design of the feedwater system is essentially identical to that of Unit 1, the magnitude of the feedwater temperature change resulting from bypassing a heater train would be the same as that observed during the Unit 1 test. Thus, the only variable is the response of the Unit 2 automatic control systems (rod control, pressurizer pressure control, pressurizer level control, steam dump control, feedwater pump speed control, and steam generator level control). Data from the Unit 1 startup test program are used in the original calibration of these control systems; therefore, their response should be similar to that of the Unit 1 systems. Because of the use of Unit 1 data in calibrating Unit 2 instrumentation and because of the observation during other startup tests on Unit 2, it is reasonable to assume that the Unit 2 control systems will respond in a manner similar to that of the Unit 1 control systems. In addition, the responses of the Unit 2 control systems will be observed and fine tuned, as necessary, as part of other startup tests. Therefore, the staff concludes that it is not necessary to perform this test on Unit 2 and the licensee's modification to eliminate the test is acceptable.

The licensee modified the abstracts for the component cooling water system functional test (Table 14.2.12-1, page 13) and the nuclear service water functional test (Table 14.2.12-1, page 16a) to delete the acceptance criteria that flows to essential components would be equal to or greater than the nominal values stated in FSAR Chapter 9. These acceptance criteria were replaced with criteria that state that flow to essential components will correspond to the nominal values in Chapter 9. By letter dated February 18, 1986, the licensee clarified the meaning of this revised wording. According to that letter, the actual test acceptance criteria were developed by the licensee's Design Engineering Department and the actual acceptance criteria flows are equal to or greater than those required for emergency cooling. With that clarification, the staff finds this change acceptable.

The abstract for the 125-V dc vital instrumentation and control power test (Table 14.2.12-1, page 21) was revised to indicate that actual bus loads would be compared with design loads only for Unit 1. To provide assurance that Unit 2 actual vital bus loads do not exceed design assumptions (which could result in faster-than-assumed battery depletion), the licensee committed, prior to exceeding 5% power, to measure the actual loads on the vital buses or to provide other confirmatory information based on the similarity of Unit 2 to Unit 1 and the measurements performed on Unit 1.

On the basis of the above discussion, the staff has concluded that the licensee's description of the initial test program and the commitment to provide additional confirmatory information are acceptable.

This review was performed with the assistance of personnel from Battelle Pacific Northwest Laboratories.

15 ACCIDENT ANALYSIS

15.6 Anticipated Transients Without Scram

Introduction

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

(1) Post-Trip Review

The first action item, Post-Trip Review, consists of Action Item 1.1, "Program Description and Procedure" and Action Item 1.2, "Data and Information Capability." This supplement to the Catawba Safety Evaluation Report (SSER 5) addresses both action items.

Action Item 1.1: Program Description and Procedure*

Review Guidelines

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

*By letter dated June 21, 1985, the staff transmitted this section to the licensee.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- The criteria for determining the acceptability of restart.

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

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

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

Evaluation and Conclusion

By letter dated November 4, 1983, the licensee provided information regarding Catawba's post-trip review program and procedures. The NRC staff evaluated the licensee's program and procedures against the review guidelines for Item 1.1 developed as described above. A brief description of the licensee's response and the staff's evaluation of the response against each of the review guidelines is provided below:

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

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

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

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

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

On the basis of staff review, the licensee's Post-Trip Review Program and Procedures for Catawba Nuclear Station, Units 1 and 2, are acceptable.

Action Item 1.2: Data and Information Capability

Review Guidelines

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

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

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

 - Each analog time history data recorder should have a sample interval small enough so that the incident can be accurately reconstructed following a reactor trip. As a minimum, the licensee should be able to reconstruct the course of the transient and accident sequences evaluated in the accident analysis of Chapter 15 of the plant FSAR. The recommended guideline for the sample interval is 10 seconds. If the time history equipment does not meet this guideline, the licensee should show that the time history capability is sufficient to accurately reconstruct the transient and accident sequences presented in FSAR

Chapter 15. To support the post-trip analysis of the cause of the trip and the proper functioning of involved safety-related equipment, each analog time history data recorder should be capable of updating and retaining information from approximately 5 minutes before the trip until at least 10 minutes after the trip.

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

B. The SOE and time history recording equipment should monitor sufficient digital and analog parameters, respectively, to ensure that the course of the reactor trip and post-trip events can be reconstructed. The parameters monitored should provide sufficient information to determine the root cause of the unscheduled shutdown, the progression of the reactor trip, and the response of the plant parameters and protection and safety systems to the unscheduled shutdowns. Specifically, all input parameters associated with reactor trips, safety injections, and other safety-related systems, as well as output parameters sufficient to record the proper functioning of these systems, should be recorded for use in the post-trip review. The parameters deemed necessary, as a minimum, to perform a post-trip review that would determine if the plant remained within its safety limit design envelope are presented in Table 15.6. These parameters were selected on the basis of staff engineering judgment following a complete evaluation of utility submittals. If the licensee's SOE recorders and time history recorders do not monitor all of the parameters suggested in this table, the licensee should show that the existing set of monitored parameters is sufficient to establish that the plant remained within the design envelope for the accident conditions analyzed in FSAR Chapter 15.

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

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

Evaluation and Conclusion

By letter dated November 4, 1983, the licensee provided information regarding its post-trip review program data and information capabilities for Catawba and McGuire Nuclear Stations. The staff evaluated the licensee's submittals against the review guidelines described above. Licensee deviations from these guidelines were reviewed with the licensee by telephone on May 23, 1985.* A brief description of the licensee's responses and the staff's evaluation of the responses against each of the review guidelines is provided below:

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

B. The licensee has established and identified the parameters to be monitored and recorded for post-trip review. On the basis of staff review and on information obtained during the May 23 telephone review, the staff finds that the parameters selected by the licensee include most of those identified in Table 15.6. The licensee did not record all of the SOE parameters recommended for Item 1.2 in Review Guideline B. The staff finds that control rod position is not recorded for all rods; this information is only available in a control room display. Safety injection flow is not recorded on the SOE recorder; however, pump and valve status is recorded. Feedwater flow and steam flow (trip parameters) are not recorded; however, the licensee states that these are not trip parameters for the plants. The licensee recorded all of the time history parameters listed for Item 1.2 in Review Guideline B. The staff finds that alternative data sources for those parameters not recorded on the SOE recorder are available for the post-trip review. Consequently, the staff finds that the licensee's selection of parameters meets the intent of the guidelines described for Item 1.2 in Review Guideline B and is, therefore, acceptable.

C. The licensee has described the means for storage and retrieval of the information gathered by the SOE and time history recorders, and for the presentation of this information for post-trip review and analysis. On the basis of its review and on information obtained during the May 23 telephone review, the staff finds that this information is being presented in a readable and meaningful format, and that the storage, retrieval, and presentation conform to the guidelines for Item 1.2 of Review Guideline C.

D. The licensee earlier informed the staff that the data and information used during post-trip reviews would be retained for no more than 6 years. The staff found that the licensee's program for data retention did not conform to Review Guideline D, which recommends that information gathered during a post-trip review be retained for the life of the plants. Consequently, by letter dated August 23, 1985, the licensee noted that ANSI N45.2.9 (1974) deals with record retention requirements, and that the licensee would pursue a definitive resolution of this matter with the appropriate ANSI committee. The licensee also stated that pending this resolution, it would retain data and information used in post-trip reviews. The NRC staff finds this licensee position and commitment to be acceptable.

---

*Teleconference between K. Jabbour, D. Hood, R. Froelich, J. Kramer, T. Bournia (NRC), and R. Sharpe et al. (Duke).

On the basis of its review, and in view of the licensee's commitment regarding the record retention period for data and information used in post-trip reviews, the staff concludes that the licensee's post-trip review data and information capabilities for Catawba Nuclear Station, Units 1 and 2, are acceptable.

(3) Post-Maintenance Testing

Introduction

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

Action Items 3.1.3 and 3.2.3: Reactor Trip System Components and All Other Safety-Related Components

Requirement

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

Evaluation

The licensee for the Catawba Nuclear Station, Units 1 and 2, responded to these requirements with a submittal dated November 4, 1983. The licensee stated in this submittal that there were no postmaintenance testing requirements in Technical Specifications for either reactor trip system or other safety-related components which degraded safety.

Conclusion

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

(4) Reactor Trip System Reliability Improvements

The fourth action item, Reactor Trip System Reliability Improvements, includes Action Item 4.2.4, "Component Replacement Program for the Reactor Trip Breakers."

Action Item 4.2.4: Component Replacement Program for the Reactor Trip Breakers*

By letter dated December 31, 1984, the licensee stated that the scheduled implementation date for the component replacement program for the reactor trip breakers (Action Item 4.2.4) was incorrectly stated as December 31, 1984, in

---

*By letter dated January 17, 1985, the staff transmitted this section to the licensee together with the full-power operating license for Unit 1.

the November 2, 1984, response. On the basis of timely receipt of the new Westinghouse manual, the licensee expects implementation of the component replacement program by the end of the first scheduled refueling outage. The staff recognizes that Item 4.2.4 is a low-priority preimplementation review item, and agrees with the new implementation schedule as proposed by the licensee. The staff will condition the full-power license to reflect the licensee's submittals dated November 2 and December 31, 1984.

Table 15.6 PWR parameter list

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

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

17 QUALITY ASSURANCE*

The Atomic Safety and Licensing Board (ASLB), in a Partial Initial Decision (PID) issued on June 22, 1984, required actions to be performed by Duke Power Company and/or NRC staff concerning several areas at Catawba Unit 1. The staff stated in SSER 4: "With the exception of the modifications of procedures relative to harassment, the staff's and the licensee's actions have been complete and adequate."

By letter dated December 17, 1984, the licensee has advised the staff that a revised management procedure, "Harassment of Employees," was issued on December 1, 1984. The December 17, 1984 letter stated that the revised procedure would be communicated to employees by December 21, 1984.

The staff has determined by inspection that the licensee has implemented Management Procedure No. 8901-0019, "Harassment of Employees," dated December 1, 1984, and that this procedure properly addresses the ASLB concerns, including training of licensee personnel.

This issue has been satisfactorily resolved and is further detailed in NRC Inspection Report Nos. 50-413/84-102 and 50-414/84-47.

---

*By letter dated January 17, 1985, the staff transmitted this section to the licensee together with the full-power operating license for Unit 1.

18 CONTROL ROOM DESIGN REVIEW

18.2 Discussion

Differences Between Unit 1 and Unit 2 Control Rooms

The licensee performed a study to document the differences between the Unit 1 and Unit 2 control rooms. By letter dated March 28, 1984, the licensee documented these differences and committed to modifying the Unit 2 control room to include all detailed control design review (DCRDR) modifications made on Unit 1. A commitment was also made to further modify the Unit 2 control room based upon the identification of additional human engineering design deficiencies found in the Unit 1 and Unit 2 control room difference study.

The staff finds that the licensee's DCRDR submittal of March 28, 1984, for Catawba Nuclear Station, Unit 2, meets all of the requirements of Supplement 1 to NUREG-0737. On November 8, 1985,* the NRC staff verified that the licensee has generally satisfied the commitments for control room modifications before fuel load; in fact, the licensee has exceeded its commitment by also including some of the modifications scheduled between fuel load and the end of the first refueling outage. As of November 8, 1985, the NRC staff has reviewed 77 design changes and found only minor deviations from design change plans. The NRC staff intends to discuss these deviations with the licensee and verify licensee resolution before fuel load.

A license condition is required to close out the DCRDR for Unit 2. Suggested license condition 33 of this supplement follows:

> Duke Power Company shall correct all human engineering deficiencies according to the schedule contained in the letter from H. B. Tucker of the Duke Power Company to H. R. Denton of the NRC, dated March 28, 1984.

18.3 Safety Parameter Display System

All holders of operating licenses issued by the Nuclear Regulatory Commission (licensees) and applicants for an operating license (OL) must provide a safety parameter display system (SPDS) in the control room of their plants. 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

---

*See IE Inspection Reports 414/85-56 and 413/85-85, issued December 16, 1985.

each identified function for a wide range of events, including 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 (V&V) 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 an SER or SER supplement.

The staff review for licensees requesting a preimplementation review and for applicants consists of a review of SPDS documentation (i.e., safety analysis report and implementation plan) and audit meetings/site visits.

After an initial review of the licensee/applicant's submittals, three separate audit meetings/site visits, as described below, may be arranged through the NRC staff. As dictated by the comprehensiveness of the applicant/licensee's documentation and the schedule for design and implementation of the SPDS, the objectives of these audits may be met in fewer site visits.

Design Verification Audit:

The purpose of this audit meeting is to obtain additional information required to resolve any outstanding questions about the V&V program, to confirm that the V&V program is being correctly implemented, and to audit the results of the V&V activities to date. At this meeting, the applicant should provide a thorough description of the SPDS design process. Emphasis should be placed on how the applicant/licensee is ensuring that the implemented SPDS will: provide appropriate parameters, be isolated from safety systems, provide reliable and valid data, and incorporate good human engineering practice.

Design Validation Audit:

After review of all documentation, an audit may be conducted to review the as-built prototype or installed SPDS. The purpose of this audit is to ensure that the results of the applicant/licensee's testing demonstrate that the SPDS meets the functional requirements of the design and to ensure that the SPDS exhibits good human engineering practice.

Installation Audit:

As necessary, a final audit may be conducted at the site to ascertain that the SPDS has been installed in accordance with the applicant/licensee's plan and is functioning properly. A specific concern is that the data displayed reflect the sensor signal which measures the variable displayed.

Unlike licensees of operating reactors, applicants will undergo, before implementation, a full review to determine whether the applicable provisions of Supplement 1 to NUREG-0737 have been satisfied. To the extent possible, the staff will temper its review to conform to the schedule for licensing and SPDS implementation.

Since the Catawba SPDS was in an advanced stage of development when the staff's review began, a combined design verification and design validation audit was conducted on May 14-15, 1985.

18.3.1 Summary

Duke Power Company (the licensee) submitted for staff review documentation regarding the SPDS for Catawba Nuclear Station (letter from licensee, March 28, 1984). The staff had requested information from the licensee on September 14, 1984. The licensee responded in a letter dated October 18, 1984. Subsequently an onsite design verification/validation audit was scheduled. The audit was conducted on May 14-15, 1985. Specific findings were documented in an audit report (letter to licensee, September 10, 1985). The NRC issued another request for information on October 31, 1985. The licensee responded to the audit findings and to the second request for information in its letter dated November 27, 1985. Clarification of the licensee's positions regarding parameter selection and the scope of the SPDS was obtained in teleconferences on December 11 and 18, 1985.*

On the basis of the above review, the staff concludes that the Catawba SPDS does not fully meet the applicable provisions of Supplement 1 to NUREG-0737. However, since the staff did not identify any serious safety concerns with the existing system, the Catawba SPDS may be operated as an interim implementation until the open issues identified herein are resolved.

18.3.2 SPDS Description

The Catawba SPDS is essentially a software implementation on the existing plant process computer. The SPDS displays are presented on cathode-ray tubes (CRTs) that are an integrated part of the control room. Operator access to displays is through the existing keyboards that are also used for accessing other plant programs and displays. The capability for continuous monitoring of plant safety status is provided in the form of six critical safety function blocks displayed at the bottom of the "alarm video," a CRT centrally located on the main control board. In addition, the critical safety function blocks may be displayed on two other CRTs that are available in the control room.

18.3.3 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).

---

*Teleconferences between K. Jabbour, G. Lapinsky, F. Orr (NRC), and R. Sharpe et al. (Duke).

In the evaluation of the SPDS, the staff has considered the Westinghouse Owners Group's "Westinghouse Emergency Response Guidelines (ERGs) Program," which was reviewed and approved by the staff (Generic Letter 83-22), as a principal technical source of variables important to operational safety. The SPDS variables selected by the licensee and their coordination with the CSFs are summarized in the licensee's response (Rev. 4) to Supplement 1 to NUREG-0737, forwarded to the staff by letter from the licensee (March 28, 1984).

The staff has reviewed the licensee's Safety Analysis Report on the Catawba SPDS. Although the variables selected do constitute a generally comprehensive list, the following important variables are not proposed for the Catawba SPDS:

(1) hot-leg temperature
(2) residual heat removal (RHR) flow rate
(3) stack monitor
(4) steam generator (or steamline) radiation
(5) containment isolation

Hot-leg temperature is a key indicator used in the ERGs (Revision 1, "ES-0.1, Attachment A," "Generic Instrumentation," page 3) to determine the viability of natural circulation as a mode of heat removal. The licensee, in a letter dated March 28, 1984, indicates "NC system temperature" as a proposed variable, but does not specify hot-leg temperature.

In its submittal of November 27, 1985, the licensee stated that wide-range hot-leg RTDs are utilized as inputs to monitor subcooling. The staff finds this position unacceptable because specific, actual values are not displayed. It is the staff's opinion that the current value of hot-leg temperature must be displayed in order for an operator to accurately assess whether natural circulation can be initiated and maintained as a mode of heat removal.

During RHR and emergency core cooling system modes of cooling when steam generators are not available, RHR flow is a key indicator to monitor the viability of the heat removal system. Steamline (or steam generator) radiation, in conjunction with containment radiation and reactor stack radiation, gives a rapid assessment of radiation status for the most likely radioactive release paths to accomplish the "radioactivity control" safety function. For a rapid assessment of radioactivity control, the licensee has not demonstrated how radiation in the secondary system (steam generators and steamlines) is monitored by the SPDS when the steam generators and/or their steamlines are isolated.

In its submittal of November 27, 1985, the licensee stated that loss of RHR flow will result in a loss of RCS inventory and a reduction in core cooling. Although this may be true, it does not address the staff's concern, i.e., the viability of the heat transfer process (rather than the effects of that process). Nor did the licensee's response address the staff's concern about monitoring radiation release paths, in particular the status of the steam lines and steam generators. The licensee has limited its discussion about SPDS to actions in plant emergency procedures. Supplement 1 to NUREG-0737 calls for the SPDS to be available for continuous assessment of plant safety status during normal, abnormal, and emergency conditions. It also calls for information to be provided relevant to radioactivity control. Since the McGuire SPDS does not provide some indication of steam generator radiation, the staff concludes that these provisions of Supplement 1 have not been fully satisfied. For example, if after a steam generator tube rupture incident, it was deemed necessary to no longer isolate the faulted steam generator, it appears unlikely that the operator could assess the steam generator radiation status to ascertain the advisability of such action and determine appropriate disposition of steam generator fluid.

Containment isolation is an important parameter for use in making a rapid assessment of "containment conditions." In particular, a determination that known process pathways through containment have been secured provides significant additional assurance of containment integrity.

In the submittal of November 27, 1985, the licensee stated that the status of containment isolation can be verified at any time by checking the monitor light panels in the control room. The staff finds this explanation unacceptable. Assumedly, most important variables that are displayed on the SPDS are also displayed and verifiable on existing control panels. This should be true if the design basis of the control room was comprehensive and correct. The SPDS is not intended to replace control room indications, it is intended to gather together important indications so that they can be observed concurrently in a concise display. The monitor light panels referred to in the licensee's response do not provide this capability.

The above variables do, for given scenarios, provide unique inputs to the determinations of status for their respective CSFs, which have not been discussed by the licensee as being satisfied by other variables in the proposed Catawba SPDS list. The staff recommends that the licensee address these variables and their functions by: (1) adding the variables to the Catawba SPDS or (2) providing alternate added variables along with justifications that these alternates accomplish the same safety functions for all scenarios.

On the basis of this review of the licensee's supporting analysis, and the observation that the selected variables appear to be consistent with the Westinghouse Owners Group ERGs, the staff finds the proposed list of key variables to be generally acceptable, with exceptions noted above.

Finally, design flexibility should be provided for possible future expansion of the SPDS. For example, with consideration of the Westinghouse Owners Group ERGs and with possible amendments to the ERGs, other key variables may be identified to assess the safety status of the CSFs.

18.3.4 Display Data Validation

The staff reviewed the licensee's submittals to determine that means are provided in the design to ensure that the data displayed are valid.

The method of data validation currently used in the Catawba SPDS is range/status checking supplemented by redundant sensor logic if more than one sensor is available.

Each computer analog input is continuously monitored for overrange and underrange conditions, scan lockout, and out-of-service status. Digital input power fuses are also monitored. When an input involving a function becomes invalid (blown fuse, over/under range, out of service, etc.), but the CSF status can still be determined from the remaining inputs, an alarm indicating an invalid input for the particular function affected is displayed. If the invalid input affects the determination of the status, the affected CSF block changes to magenta (indicating an indeterminate condition), and remains in this state until the invalid input can be corrected or until the input is locked out to a known valid value or status.

The staff finds this method to be acceptable as an interim measure based on the fact that the licensee is involved in an Electric Power Research Institute (EPRI) project investigating signal validation techniques and is committed to evaluating the results of that program (EPRI Project RP-2292-1, "Validation and Integration of PWR Signals") to improve the current data validation methodology, if feasible.

Information Needed for Confirmatory Review

A description of the improvements to the current data validation methodology should be submitted to the staff when the licensee has finished studying the data validation methodology, i.e., incorporated appropriate techniques from the EPRI study. This information should be submitted no later than August 1, 1987.

18.3.5 Human Factors Program

The staff evaluated the licensee's submittals for a commitment to a human factors program in the development of the SPDS.

The licensee has attempted to incorporate good human engineering principles into the Catawba SPDS design at several points in the design process. Initially, when the design was conceptualized in early 1982, the design basis was independently reviewed by an EPRI staff member who had experience in SPDS design. Since the design logic is based on the status trees of the Westinghouse ERGs, it also benefited from the Westinghouse human factors input, albeit indirectly.

However, the bulk of the human factors input was derived from coordination with the licensee's efforts on the DCRDR. During the SPDS development, the control room review team conducted a task analysis using a mockup and color slides of proposed SPDS displays. The analysis also examined the order and format of supporting (non-SPDS) displays, their usability, and ability to support operator tasks as defined in the Westinghouse ERGs. After implementation,* the control room review team surveyed the computer displays, including the SPDS, using a checklist that was derived from NUREG-0700. Areas of review included color usage, glare, labels, keyboard arrangement, as well as other human factors issues. In addition, operator comments were solicited as part of the Operating Experience Review phase of the DCRDR.

The staff identified no significant deviations from good human engineering practice in the SPDS displays or interface devices. However, the staff did identify

*Development of the Catawba SPDS was actually done on the McGuire plant - the Catawba and McGuire SPDSs are conceptually and programmatically identical.

a significant problem in the content of the SPDS displays. As currently defined by the licensee, the scope of the Catawba SPDS encompasses only the six color blocks that are intended to represent the status of the critical safety functions. The licensee does not consider any of the supporting displays such as the Emergency Operating Procedure status tree displays and input displays lists to be a part of the SPDS. Given this limited scope, the staff concludes that the CSF color blocks do not provide sufficient information from which an operator can assess the safety status of the plant. First, the CSF color blocks do not include as inputs all of the variables judged by the staff to be necessary for assessment of the critical safety functions (see Section 18.3.3 of this supplement). The staff requires that the variables listed below be added to the Catawba SPDS:

(1) hot-leg temperature
(2) RHR flow rate
(3) stack monitor
(4) steam generator (or steamline) radiation
(5) containment isolation

Secondly, the color blocks do not provide the actual value of the input variables, so the operator cannot determine either the current state of a variable or its trend. It is also impossible to determine which variable is in alarm using the Catawba SPDS, i.e., the CSF color blocks. Therefore, the staff requires that the Catawba SPDS be redesigned/defined to include the actual value of all of the SPDS input variables as well as the five additional variables discussed above. These actual values should be provided on easily accessible, logically grouped displays similar to those now defined as supporting displays, e.g., status tree displays, CSF input list displays.

18.3.6 Electrical and Electronic Isolation

The SPDS at Catawba is software implemented on the operator aid computer (OAC) system. This system consists of a Honeywell model 4400 computer and bulk core memory. The system displays are driven by an Aydin 5205-C color graphic video display generator. Alarm typers, printers, and floppy disk drives are also utilized. The OAC has both Class 1E and non-Class 1E sensor inputs. The Class 1E inputs are isolated from the OAC by qualified isolation amplifiers, Westinghouse series 7300, that were reviewed and accepted by the staff in the following documents: (1) WCAP-8892-A, "Westinghouse 7300 Series Process Control System Noise Tests," June 1977, and (2) NRC letter from R. Tedesco to C. Eicheldinger, Westinghouse Electric Company, April 20, 1977. The only exception to this configuration is the interface between the high-range containment radiation channels and the SPDS - these are isolated using E-MAX devices.

The E-MAX devices were subjected to dielectric and transverse mode tests. The dielectric test was performed using [illegible]0-V RMS (root mean square) applied to the input and output connections. The device passed this test satisfactorily with no breakdown of the dielectric. For the transverse mode test, the maximum credible fault was determined to be 120-V ac limited to 20 amperes.

This fault voltage was applied across the plus and minus outputs of the device. The device was energized in the normal fashion with separate sources, and a storage type oscilloscope (scope) was connected to the input to detect any propagation of the fault to the input signal circuitry. The pass/fail criterion for the transverse mode test was that on application of the fault to the output circuitry (non-Class 1E side), the input circuitry (Class 1E side) must sustain no damage, and the fault should not propagate to the input.

On the application of the fault, the input circuitry scope recorded a 147 millivolt (mV) spike of a few milliseconds' duration. This low-voltage spike was attributed to noise being generated as the output circuit components were being destroyed. The noise spike was not detrimental to the input circuit.

On the basis of an audit of the above documentation on isolation amplifiers and the E-MAX isolators, the topical report, and the previous staff approval of this report, the staff concludes that these devices are acceptable for interfacing the OAC/SPDS with safety-related systems, and that this equipment meets the Commission's requirements as stated in NUREG-0737, Supplement 1.

18.3.7 Conclusions

On the basis of its documentation review and onsite audit, the staff concludes that the Catawba safety parameter display system does not fully meet the applicable requirements of Supplement 1 to NUREG-0737 because the variables included in the SPDS are not sufficient to provide the minimum information required to assess the critical safety functions. In addition, the SPDS variables are not displayed for operator viewing - only alarm boxes are displayed.

To resolve this deficiency, the licensee should add the following five variables to the SPDS:

(1) hot-leg temperature
(2) RHR flow rate
(3) stack monitor
(4) steam generator (or steamline) radiation
(5) containment isolation status

In addition, all SPDS variables, including the five listed above, should be displayed for operator viewing. These displays should be logically grouped and easily accessible.

Because the staff did not identify any serious safety questions concerning the Catawba SPDS, the staff concludes that it is acceptable as an interim implementation and may be used until startup following the first refueling outage. The facility's Operating License NPF-48 is conditioned to require the addition of the five parameters listed above. License condition 50 is added in this supplement.

23 CONCLUSIONS

On the basis of its evaluation of the application as set forth in its SER dated February 1983 and Supplements 1, 2, 3, and 4 and its evaluation as set forth in this supplement, the staff concludes that an operating license can be issued to allow initial criticality and power ascension to full-power operation for the Catawba Nuclear Station, Unit 2.

The staff concludes that the construction of the facility has been completed in accordance with the requirements of 10 CFR 50.57(a)(1) sufficient to support initial criticality and power ascension to full-power operation and that construction of the facility has been monitored in accordance with the inspection program of the Commission's staff.

Subsequent to the issuance of the operating license for initial criticality and power ascension to full-power operation for the Catawba Nuclear Station, Unit 2, the facility may then be operated only in accordance with the Commission's regulations and the conditions of the operating license under the continuing surveillance of the Commission's staff.

The staff concludes that the activities authorized by the license can be conducted without endangering the health and safety of the public and reaffirms its conclusions as stated in the SER and its supplements.

APPENDIX A

CONTINUATION OF CHRONOLOGY

November 30, 1984	Letter from licensee concerning maintenance and inspection of diesel generators.
December 5, 1984	Letter from licensee concerning Transamerica Delaval, Inc. (TDI) diesel generators.
December 6, 1984	Letter to licensee forwarding Operating License No. NPF-31 authorizing operation up to 5% power.
December 12, 1984	Commission issues Order to parties to provide comments regarding effectiveness of Atomic Safety Licensing Board's (ASLB's) full-power decision by December 28, 1984.
December 13, 1984	Atomic Safety Licensing Appeal Board (ASLAB) issues Order requiring responses to intervenors' application for a stay by December 21, 1984.
December 14, 1984	Supplement No. 4 to Safety Evaluation Report issued.
December 14, 1984	Letter from licensee concerning alarm in the control room for boron dilution events in all modes of operation.
December 17, 1984	Letter from licensee concerning quality assurance issues.
December 17, 1984	Letter from licensee forwarding Revision 7 to Pump and Valve Inservice Testing Program.
December 17, 1984	Letter from licensee concerning post-fuel-loading initial test program.
December 18, 1984	Letter to licensee requesting additional information related to safety parameter display system.
December 18-19, 1984	Meeting with licensee to discuss pump and valve inservice testing program. (Summary issued January 23, 1985.)
December 19, 1984	Letter from licensee responding to request for additional information regarding Topical Report DPC-NF-2010, "Nuclear Physics Methodology for Reload Design."
December 24, 1984	ASLAB issues Memorandum and Order denying intervenors' application for a stay of three partial initial decisions of ASLB.

December 27, 1984	Generic Letter 84-24 issued: "Certification of Compliance to 10 CFR 50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants."
December 31, 1984	Letter from licensee concerning review of vendor engineering recommendations for reactor trip system components (Generic Letter 83-28).
December 31, 1984	Letter from licensee concerning incore thermocouple system.
January 2, 1985	Letter from licensee concerning changes to the post-fuel-loading initial test program.
January 8, 1985	Letter from licensee concerning implementation of inadequate core cooling instrumentation.
January 8, 1985	Letter from licensee forwarding Inservice Inspection Plan.
January 9, 1985	Generic Letter 85-01 issued: "Fire Protection Policy Steering Committee Report."
January 10, 1985	Letter from licensee advising that sale of 25% ownership of Unit 2 to Piedmont Municipal Power Agency has been completed.
January 10, 1985	Letter from licensee concerning detailed Inservice Inspection Plan.
January 11, 1985	Letter from licensee concerning changes to post-fuel-loading initial test program.
January 14, 1985	Letter to licensee concerning changes to post-fuel-loading initial test program.
January 14, 1985	Letter from licensee concerning training program for licensed operators.
January 17, 1985	Letter to licensee transmitting Facility Operating License No. NPF-35 authorizing operation at 100% power.
January 18, 1985	Letter to licensee concerning review of the reactor coolant system four pump flow coastdown.
January 18, 1985	Letter from licensee advising that construction completion date for Unit 2 has been changed to January 1986.
January 23, 1985	Letter from licensee concerning the safety parameter display system.
January 24, 1985	ASLAB issues Order granting in part licensee's motion to submit a 110-page brief in connection with appeals from initial decisions.

January 29, 1985	Generic Letter 85-04 issued: "Operator Licensing Examinations."
January 31, 1985	Generic Letter 85-05 issued: "Inadvertent Boron Dilution Events."
January 31, 1985	Letter from licensee concerning limited operational fog-monitoring program.
February 12, 1985	Letter from licensee forwarding bimonthly report on status of confirmatory research program for main steamline break accidents.
February 14, 1985	Letter from licensee concerning leak-before-break concept for Unit 2.
February 15, 1985	Letter from licensee forwarding Revision 8 to Inservice Testing Program and responding to open items.
February 22, 1985	Board Notification 85-018 issued: "Transcript of Meeting Held on February 11, 1985, Between the NRC and the Transamerica Delaval, Inc. (TDI) Diesel Generator Owners Group."
February 26, 1985	ASLAB issues Order scheduling oral argument on the appeals of Palmetto Alliance and Carolina Environmental Study Group from the ASLB's three partial initial decisions.
March 1, 1985	Letter from licensee concerning shift operator experience requirements.
March 13, 1985	Letter to licensee concerning topical report on physics methodology for reloads.
March 15, 1985	Letter from licensee concerning safety parameter display system.
March 18, 1985	Letter from licensee concerning emergency preparedness information required by license condition 23.
March 21, 1985	Letter from licensee concerning conformance to staff position on design requirements of the reactor heat removal system (RHRS) and steam generator tube rupture.
March 28, 1985	Letter from licensee concerning successfully conducted turbine trip required by license condition 13.
March 28, 1985	Letter from licensee concerning safety-significant differences in emergency procedures from the NRC-approved Westinghouse Owners Group generic technical guidelines.
March 29, 1985	Letter from licensee forwarding Revision 12 to "An Analysis of Hydrogen Control Measures at McGuire Nuclear Station."

March 29, 1985	Letter from licensee forwarding Revision 9 to "Inservice Testing Program."
April 3, 1985	Letter from licensee concerning status of diesel engine wiring and terminations with regard to TDI Owners Group recommendations.
April 11, 1985	Letter from licensee forwarding status report on confirmatory research program of tests and analyses regarding containment response for main steamline break accidents.
April 11, 1985	Letter from licensee concerning tests and analysis of transformer tap settings before full power reactor operation.
April 16, 1985	Generic Letter 85-06 issued: "Quality Assurance Guidance for ATWS Equipment That Is Not Safety-Related."
April 17, 1985	Generic Letter 85-02 issued: "Staff Recommended Actions Stemming From NRC Integrated Program for the Resolution of Unresolved Safety Issues Regarding Steam Generator Tube Integrity."
April 17, 1985	Letter from licensee forwarding revision to "Emergency Plan Implementing Procedures."
April 18, 1985	Letter to licensee granting request for withholding information from public disclosure.
April 19, 1985	Letter from licensee concerning antitrust review.
April 23, 1985	Letter to licensee granting request for exemption from a portion of GDC 4 of Appendix A to 10 CFR 50 regarding the need to analyze large primary loop pipe ruptures as a structural design basis for Unit 2.
April 25, 1985	ASLAB issues Order directing all parties to submit memoranda concerning storage of Oconee and McGuire spent fuel at Catawba.
April 26, 1985	Letter from licensee concerning instrumentation for inadequate core cooling.
April 30, 1985	Letter from licensee concerning extended operation tests and inspection of diesel generators.
April 30, 1985	Letter from licensee concerning deviations between Catawba Station Emergency Procedure Guidelines and the Westinghouse Owners Group Emergency Response Guidelines.
May 1, 1985	Letter from licensee concerning scope of fog-monitoring program required by the Environmental Protection Plan.

May 2, 1985	Generic Letter 85-07 issued: "Implementation of Integrated Schedules for Plant Modifications."
May 6, 1985	Letter to licensee forwarding Amendment No. 3 to Construction Permit CPPR-117 for Unit 2. The amendment modifies the construction permit to reflect the issuance of an exemption dated April 23, 1985.
May 14, 1985	Letter to licensee concerning item 2 in condition 2.C.(23) of Unit 1 license.
May 14-15, 1985	Meeting with licensee to audit Unit 2 safety parameter display system. (Summary issued June 13, 1985.)
May 16, 1985	Letter to licensee concerning Draft Technical Evaluation Report for Salem ATWS Item 1.2 (Generic Letter 83-28).
May 17, 1985	Letter from licensee transmitting Amendment 34 to application for operating licenses, Revision 12 to FSAR.
May 22, 1985	Letter from licensee forwarding Revision 1 to "Inservice Inspection Plan."
May 22, 1985	Letter from licensee forwarding Significant Deficiency Report No. 414/85-06.
May 23, 1985	Generic Letter 85-08 issued: "10 CFR 20.408 Termination Reports - Format."
May 23, 1985	Generic Letter 85-09 issued: "Technical Specifications for Generic Letter 83-28, Item 4.3."
May 31, 1985	Letter from licensee concerning fire protection program.
May 31, 1985	Letter from licensee forwarding Significant Deficiency Report No. 414/85-08.
June 3, 1985	ASLAB issues Order granting licensees right to file response to staff's May 29, 1985, filing regarding storage of spent fuel generated at Oconee.
June 3, 1985	Letter to licensee concerning condition 2.C.(23) of Unit 1 license.
June 3, 1985	Letter from licensee concerning financial protection for licensed operating nuclear reactors.
June 4, 1985	Letter to licensee requesting additional information regarding items 4.1, 4.2.1, and 4.2.2 of Generic Letter 83-28.
June 7, 1985	Letter to licensee forwarding copy of "Notice of Receipt of Antitrust Information."
June 12, 1985	Letter from licensee concerning license condition 23.

June 13, 1985	ASLAB issues Order scheduling supplemental oral argument on pending appeals to be heard on June 28, 1985.
June 17, 1985	ASLAB issues Order regarding June 28, 1985, oral argument.
June 17, 1985	Letter from licensee concerning steam generator tube integrity (Generic Letter 85-02).
June 21, 1985	Letter to licensee concerning safety evaluation regarding Generic Letter 83-28, Item 1.1 (Post-Trip Review).
June 21, 1985	Letter from licensee concerning Generic Letter 83-28, Items 4.2.1 and 4.2.2.
June 21, 1985	Letter from licensee concerning TDI Diesel Generator Owners Group, "Design Review/Quality Revalidation Report."
June 21, 1985	Letter to licensee concerning data and information capability for Post-Trip Review - Item 1.2 of Generic Letter 83-28.
June 24, 1985	Letter from licensee concerning Generic Letter 83-28, Items 4.2.1 and 4.2.2.
June 24, 1985	Letter from licensee concerning Seismic Qualification Review Team audit.
June 26, 1985	Letter from licensee concerning security portion of the SER.
June 26, 1985	Letter to licensee concerning TMI Action Plan Item II.K.3.30.
June 28, 1985	Generic Letter 85-11 issued: "Completion of Phase II of Control of Heavy Loads at Nuclear Power Plants, NUREG-0612."
June 28, 1985	Generic Letter 85-12 issued: "Implementation of TMI Action Item II.K.3.5, Automatic Trip of Reactor Coolant Pumps."
July 1, 1985	Letter from licensee concerning financial protection for licensed operating nuclear reactors.
July 5, 1985	Letter to licensee forwarding first draft of Technical Specifications for Units 1 and 2.
July 5, 1985	Letter from licensee forwarding response to Generic Letter 85-07, "Implementation of Integrated Schedules for Plant Modifications."
July 12, 1985	Letter from licensee concerning post-fuel-loading startup test program.

July 15, 1985	Letter from licensee forwarding update on status of all outstanding corrective actions for Significant Deficiency No. 414/85-06 as outlined in the initial report transmitted on May 22, 1985.
July 15, 1985	Letter from licensee forwarding an update on status of all outstanding corrective actions for Significant Deficiency No. 414/85-08 as outlined in the initial report transmitted on May 31, 1985.
July 17, 1985	Letter from licensee responding to Generic Letter 85-02 concerning steam generator tube integrity.
July 23-25, 1985	Meeting and site visit with licensee to discuss first draft Technical Specifications.
July 24, 1985	Letter from licensee forwarding supplement to status report dated July 15, 1985, on corrective actions taken on Significant Deficiency No. 414/85-06.
July 24, 1985	Letter from licensee forwarding supplement to status report dated July 15, 1985, on corrective actions taken on Significant Deficiency 414/85-08.
July 24, 1985	Letter from licensee transmitting Revision 6 to emergency plan.
July 24, 1985	Letter to licensee requesting additional information regarding probability of upperhead injection (UHI) isolation failure.
July 26, 1985	ASLAB issues decision affirming ASLB's authorization of the issuance of full-power operating licenses except as those licenses permit the receipt and storage on the facility site of spent fuel generated at other nuclear facilities.
July 30, 1985	ASLAB issues order making corrections to ALAB-813, dated July 26, 1985.
August 1, 1985	Generic Letter 85-14 issued: "Commercial Storage at Power Reactor Sites of Low-Level Radioactive Waste Not Generated by the Utility."
August 5, 1985	Generic Letter 85-13 issued: "Transmittal of NUREG-1154 Regarding the Davis-Besse Loss of Main and Auxiliary Feedwater Event."
August 6, 1985	Generic Letter 85-15 issued: "Information Relating to the Deadlines for Compliance With 10 CFR 50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants."
August 7, 1985	Letter from licensee forwarding revised for proposed combined Technical Specifications.

August 7, 1985	Letter from licensee forwarding copies of annual report.
August 9, 1985	Letter from licensee concerning financial protection.
August 15, 1985	Letter from licensee stating that all work associated with Significant Deficiency No. 414/85-06 is now complete.
August 22, 1985	Letter from licensee responding to Generic Letter 83-12 regarding automatic trip of reactor coolant pumps.
August 23, 1985	Letter from licensee concerning resolution of outstanding items on diesel generators.
August 23, 1985	Letter from licensee concerning retention period for data and information used for post-trip reviews.
August 23, 1985	Generic Letter 85-16 issued: "High Boron Concentrations."
August 23, 1985	Generic Letter 85-17 issued: "Availability of Supplements 2 and 3 to NUREG-0933, A Prioritization of Generic Safety Issues."
August 26, 1985	Board Notification 85-079 issued: "Issuance of Notice of Violation and Proposed Imposition of Civil Penalty Related to Discrimination by Duke Power Company at Catawba Nuclear Station."
September 4, 1985	Letter to licensee concerning interim guidance on Emergency Planning Standard 10 CFR 50.47(b)(12).
September 5, 1985	Letter from licensee forwarding Revision 10 to "Pump and Valve Inservice Testing Program."
September 7, 1985	Letter from licensee forwarding Revision 16 to "Crisis Management Plan."
September 10, 1985	Letter from licensee concerning probability of UHI isolation failure.
September 10, 1985	Letter to licensee forwarding the safety parameter display system audit results.
September 25, 1985	Meeting with licensee at site to audit the inadequate core cooling instrumentation for implementation review. (Summary issued November 7, 1985.)
September 27, 1985	Generic Letter 85-18 issued: "Operator Licensing Examinations."
October 1, 1985	Letter from licensee forwarding Amendment 35 to application for operating licenses.
October 2, 1985	Letter from licensee forwarding report on 2A diesel engine component Revalidation Inspections.

October 8, 1985	Letter from licensee providing schedule for implementation of quality assurance (QA) guidance provided by Generic Letter 85-06.
October 10, 1985	Letter to licensee forwarding proof and review copy of the combined Technical Specifications.
October 10, 1985	Letter from licensee forwarding seismic qualification test report.
October 11, 1985	Letter from licensee requesting one-time emergency amendment to Operating License NPF-35. Amendment would provide temporary extension of allowed time in mode 3 with unidentified reactor coolant system leakage greater than 1 gpm.
October 11, 1985	Letter from licensee forwarding bimonthly report on status of the confirmatory research program of tests and analyses regarding containment response for main steamline break accidents.
October 14, 1985	Letter from licensee forwarding Revision 7 to Emergency Plan.
October 14, 1985	Letter from licensee forwarding revisions to "Emergency Plan Implementing Procedures."
October 15, 1985	Letter from licensee concerning offsite emergency plans.
October 15, 1985	Letter from licensee withdrawing October 11, 1985, request for emergency license amendment.
October 16, 1985	Letter from licensee forwarding Revision 9 to security plan.
October 22, 1985	Letter from licensee responding to August 6, 1985, request for information related to Regulatory Guide 1.97, Revision 2.
October 23, 1985	Letter from licensee forwarding Revision 4 to "Safeguards Contingency Plan."
October 25, 1985	Letter from licensee forwarding the Unit 2 Pump and Valve Inservice Testing Program.
October 29, 1985	Letter from licensee concerning loss-of-coolant accident (LOCA) outside containment.
October 30, 1985	Letter from licensee providing changes to proof and review Technical Specifications.
October 31, 1985	Letter to licensee requesting additional information concerning the safety parameter display system.
November 1, 1985	Letter from licensee concerning the safety parameter display system.

November 1, 1985	Letter to licensee forwarding Amendment No. 1 to Operating License NPF-35. The amendment changes the Technical Specifications to extend, by 72 hours, on a one-time basis, the time allowed in mode 3 with unidentified reactor coolant system leakage greater than 1 gpm, but less than 5 gpm.
November 4, 1985	Letter from licensee forwarding "Design Review and Quality Revalidation Report," Revision 1, for TDI diesel generators at Catawba.
November 7, 1985	Letter from licensee providing changes to proof and review Technical Specifications.
November 8, 1985	Letter from licensee providing justification and analysis of significant hazards consideration for changes to proof and review Technical Specifications.
November 11, 1985	Letter from licensee concerning Physical Security Plan.
November 15, 1985	Letter from licensee concerning main steamline break in the doghouse.
November 15, 1985	Letter from licensee regarding the LOFTRAN Code.
November 15, 1985	Letter from licensee forwarding revision to "Emergency Plan Implementing Procedure."
November 19, 1985	Letter to licensee requesting additional information regarding main steamline break in the doghouse.
November 20, 1985	Letter from licensee concerning elimination of arbitrary intermediate breaks.
November 20, 1985	Letter from licensee concerning visual weld acceptance criteria for structural welding at nuclear power plants - training program.
November 21, 1985	Letter from licensee concerning reactor containment building integrated leak rate test.
November 21, 1985	ASLAB issues decision affirming ASLB's operating license authorization that permits the licensee to receive and store at Catawba spent fuel generated at Oconee and McGuire facilities.
November 27, 1985	Letter from licensee forwarding revisions to Pump and Valve Inservice Testing Program.
November 27, 1985	Letter from licensee concerning the safety parameter display system.
December 3, 1985	Letter from licensee concerning Generic Letter 83-28.

December 3, 1985	Generic Letter 85-22 issued: "Potential for Loss of Post-LOCA Recirculation Capability Due to Insulation Debris Blockage."
December 5, 1985	Letter from licensee concerning the fog-monitoring program.
December 9, 1985	Letter to licensee requesting additional information regarding Unit 2 TDI diesel generators.
December 10, 1985	Letter from licensee forwarding Emergency Plan Implementing Procedures revisions.
December 11, 1985	Letter from licensee concerning Physical Security Plan.
December 12, 1985	Board Notification 85-092--Diesel Generator 2B Main Bearing No. 7 Failure.
December 17, 1985	Letter to licensee transmitting draft SER and requesting additional information regarding hydrogen control measures.
December 17, 1985	Letter from licensee concerning confirmatory research program of tests and analyses regarding containment response for main steamline break accidents.
December 17, 1985	Letter from licensee providing corrections to proof and review Technical Specifications.
December 17, 1985	Letter from licensee forwarding advance copy of Revision 14 to FSAR.
December 17, 1985	Letter from licensee concerning exemption to 10 CFR 70.24 regarding criticality monitoring.
December 23, 1985	Letter from licensee on the results of the inspections and evaluations performed on the Catawba 2B diesel engine.
December 23, 1985	Letter from licensee concerning Technical Specifications for condensate storage tank.
December 23, 1985	Letter from licensee forwarding results of inspections and evaluations performed on the 2B diesel engine.
December 26, 1985	Letter from licensee providing changes to proof and review Technical Specifications.
December 30, 1985	Meeting with licensee to discuss the failure of main bearing No. 7 of TDI diesel generator 2B at Unit 2.
January 2, 1986	Letter from licensee providing changes to proof and review Technical Specifications.
January 6, 1986	Letter from licensee concerning hydrogen control.

January 7, 1986	Letter from licensee providing changes to proof and review Technical Specifications.
January 13, 1986	Letter to licensee concerning protection of auxiliary feedwater piping.
January 13, 1986	Letter from licensee concerning quality revalidation inspections of the two diesels at Unit 2.
January 16, 1986	Letter to licensee enclosing Final Draft Technical Specification for certification.
January 21, 1986	Letter from licensee advising that remaining construction and testing activities for Unit 2 will be completed and ready for fuel loading on February 26, 1986.
January 21, 1986	Letter from licensee providing additional information regarding the exemptions requested for Unit 2.
January 23, 1986	Letter from licensee concerning Safeguards Contingency Plan, Revision 5.
January 24, 1986	Letter to licensee forwarding Amendment No. 2 to NPF-35. Amendment changes the Technical Specification to permit an exception to the experience requirments for six identified candidates for senior reactor operator licenses.
January 24, 1986	Letter from licensee forwarding Revision 7 to Training and Qualification Plan.
January 30, 1986	Letter from licensee forwarding revisions to Emergency Plan Implementing Procedures.
January 31, 1986	Letter from licensee forwarding Amendment 36 to its application for licenses. Amendment consists of Revision 14 to FSAR.
February 4, 1986	Letter from licensee forwarding revised pages to Amendment 36 to application which was transmitted January 31, 1986.
February 5, 1986	Letter from licensee concerning implementation of inadequate core cooling instrumentation.
February 6, 1986	Letter from licensee concerning Preservice Inspection Program.
February 10, 1986	Letter from licensee trasmitting comments on the proposed low-power license for Unit 2.
February 10, 1986	Letter from licensee forwarding corrections to the Final Draft Technical Specifications.

February 12, 1986	Letter to licensee forwarding Notice of Environmental Assessment and Finding of No Significant Impact related to requests for exemptions from certain requirements for completing ice loading, ice weighing, and reinstallation of ice condenser components before fuel load and from certain requirements for airlock leakage tests.
February 12, 1986	Letter to licensee forwarding Amendment No. 3 to NPF-35. Amendment changes the Technical Specification to revise Surveillance Requirement 4.3.4.2 from a turbine control valve testing frequency of once in seven days to at least once in 31 days.
February 14, 1986	Letter to licensee forwarding Amendment 4 to NPF-35. Amendment changes Technical Specification 3/4.6.5.3, "Ice Condenser Doors," and its associated bases to limit the allowed time of power operation with the ice condenser inlet doors in a closed and inoperable condition and clarifies the definition of "inoperable."
February 14, 1986	Letter to licensee forwarding Amendment No. 5 to NPF-35. Amendment changes Technical Specification related to diesel generator surveillance testing.
February 18, 1986	Letter from licensee regarding acceptance criteria for preoperational testing of the component cooling water system and the nuclear service water system.
February 21, 1986	Letter from licensee certifying that to its best knowledge, the Final Draft Technical Specifications conservatively reflect the as-built plant and the FSAR. Furthermore, the licensee is not aware of any conflicts between the Final Draft Technical Specifications and the SER analyses.

APPENDIX B

BIBLIOGRAPHY

Failure Analysis Associates, FaAA-84-9-11, "Design Review of TDI R-4 and RV-4 Series Emergency Diesel Generator Cylinder Blocks," December 1984.

---, FaAA 84-5-7.1, "Design Review of Elliott Model 90 G Turbocharger Used on Transamerica Delaval DSR-48 and DSRV 16-14 Emergency Diesel Generator Sets--Nozzle Ring Assembly Supplement," November 1984.

Los Alamos National Laboratory, letter report from R. G. Gido to C. G. Tinkler, NRC, August 1, 1984.

Pacific Northwest Laboratory, PNL-5444, "Review of Design Review of Quality Revalidation Report for the Transamerica Delaval Diesel Generator at Comanche Peak Steam Electric Station Unit 1," October 1985.

---, PNL 5600, "Review of Resolution of Known Problems in Engine Components for Transamerica Delaval Inc. Emergency Diesel Generators," December 1985.

---, PNL 5718, "Review of Transamerica Delaval Inc. Diesel Generator Owners Group Engine Requalification Program," Final Report, December 1985.

Sandia National Laboratories, letter report from L. S. Nelson to P. Worthington, NRC, March 7, 1984.

Stone & Webster Co., "Supplement to the Emergency Diesel Generator Air Start Valve Capscrew Dimension and Stress Analysis," April 1984.

TDI Diesel Generator Owners Group, "TDI Diesel Generator Design Review and Quality Revalidation Report," Revision 1, February 1985.

Transamerica Delaval, Inc., SIM-300.

---, SIM-361, Revision 1.

U.S. Nuclear Regulatory Commission, Generic Letter 82-33, See NUREG-0737, Supplement 1.

---, Generic Letter 83-22, "Safety Evaluation of 'Emergency Response Guidelines,'" June 3, 1983.

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

---, Generic Letter 83-37, "NUREG-0737 Technical Specifications," November 1, 1983.

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

---, letter from R. Tedesco to C. Eicheldinger, Westinghouse, April 20, 1977.

---, letter from D. Eisenhut to J. George, TDI Owners Group, Texas Utilities Generating Co., August 13, 1984.

---, memorandum from E. G. Adensam to H. B. Tucker, August 18, 1983.

---, memorandum from E. G. Adensam to H. B. Tucker, May 8, 1984.

---, memorandum from B. Sheron to E. Adensam, September 4, 1985.

---, NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors," revised periodically.

---, NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," February 1980.

---, NUREG-0700, "Guidelines for Control Room Design Reviews," September 1981.

---, NUREG-0737, Supplement 1, "Clarification of TMI Action Plan Requirements: Requirements for Emergency Response Capability," December 1982.

---, NUREG-0989, Supplement 3, "Safety Evaluation Report Related to the Operation of River Bend Station," August 1985.

---, NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant," April 1983.

---, NUREG-1014, "Safety Evaluation Report Related to Model D4/D5 Steam Generator Design Modification," October 1983.

---, NUREG/CR-3912, "MARCH/HECTR Analysis of Selected Accidents in an Ice Condenser Containment," December 1984.

---, NUREG/CR-3954, "HECTR Analysis of Equipment Temperature Responses to Selected Hydrogen Burns in an Ice Condenser Containment," February 1985.

---, Office of Inspection and Enforcement (I&E), Information Notice 80-08, March 7, 1980.

---, I&E Inspection Report No. 50-413/84-102 and 50-414/84-47, January 15, 1985.

---, I&E Inspection Report No. 50-413/85-11, May 30, 1985.

---, I&E Inspection Report No. 50-413/85-14, May 30, 1985.

Westinghouse Corp., WCAP-8892-A, "Westinghouse 7300 Series Process Control System Noise Tests," June 1977.

Westinghouse Owners Group, "Westinghouse Emergency Response Guidelines (ERGs) Program," 1984.

---, letter from M. Sheppard to H. Thompson, NRC, May 4, 1984.

APPENDIX D

PRINCIPAL CONTRIBUTORS

NRC STAFF

Name	Title*	Branch or Section, Office (Division)*,**
G. Bagchi	Section Leader	Mechanical Engineering, NRR (PWR-A)
R. Becker	Reactor Systems Engineer	Facility Operations, NRR (BWR)
B. Clayton	Section Leader	Facility Operations, NRR (PWR-A)
L. Crocker	Section Leader	Facility Operations, NRR (PWR-A)
S. Diab	Task Manager	Reactor Safety Issues, NRR (Safety Review and Oversight)
M. Duncan	Licensing Assistant	PWR Project Directorate #4, NRR (PWR-A)
J. Fairobent	Meteorologist	Reactor Systems, NRR (PWR-A)
C. Gaskin	Plant Protection Specialist	Safeguards Reactor and Transporation Licensing, NMSS
G. Hammer	Mechanical Engineer	Mechanical Engineering, NRR (PWR-A)
P. Hearn	Senior Mechanical Engineer	Plant Systems, NRR (BWR)
T. Huang	Nuclear Engineer	Reactor Systems, NRR (BWR)
M. Hum	Materials Engineer	Engineering, NRR (PWR-B)
J. Joyce	Senior Task Manager	Reactor Safety Issues, NRR (Safety Review and Oversight)
J. Kramer	Senior Human Factors Engineer/Engineering Psychologist	Electrical, Instrumentation, and Control Systems, NRR (PWR-A)
D. Kubicki	Mechanical Engineer	Plant, Electrical, Instrumentation, and Control Systems, NRR (PWR-A)

*Reflects reorganization since Supplement 4 was issued.

**NRR - Office of Nuclear Reactor Regulation; NMSS - Office of Nuclear Material Safety and Safeguards; IE - Office of Inspection and Enforcement.

NRC STAFF (Continued)

Name	Title*	Branch or Section, Office (Division)*
G. Lapinski	Engineering Psychologist	Facility Operations, NRR (PWR-A)
J. Lazevnick	Electrical Engineer	Electrical, Instrumentation, and Control Systems, NRR (PWR-A)
W. Lyon	Senior Nuclear Engineer	Reactor Systems, NRR (PWR-A)
E. Murphy	Reactor Systems Engineer	BWR Assessment, NRR
F. Orr	Reactor Systems Engineer	Facility Operations, NRR (PWR-A)
R. Palla	Mechanical Engineer	Regulatory Improvements, NRR (Safety Review and Oversight)
J. Pulsipher	Mechanical Engineer	Mechanical Engineering, NRR (PWR-A)
H. Shaw	Mechanical Engineer	Engineering, NRR (BWR)
J. Simonds	Emergency Preparedness Specialist	Emergency Preparedness, IE
H. Walker	Mechanical Engineer	Electrical, Instrumentation, and Control Systems, NRR (PWR-A)
R. Wright	Senior Mechanical Engineer	Engineering, NRR (PWR-B)

NRC CONTRACTORS

Battelle Pacific Northwest Laboratories

Brookhaven National Laboratory

Covenant Engineering

EG&G Idaho, Inc.

Engineered Applications Corp.

Idaho National Engineering Laboratories

Sandia National Laboratories

*Reflects reorganization since Supplement 4 was issued.

**NRR - Office of Nuclear Reactor Regulation; NMSS - Office of Nuclear Material Safety and Safeguards; IE - Office of Inspection and Enforcement.

APPENDIX I

APRIL 30, 1985, MEMORANDUM FROM FEMA

Federal Emergency Management Agency

Washington, D.C. 20472

APR 30 1985

MEMORANDUM FOR: Edward L. Jordan
Director, Division of Emergency Preparedness and Engineering Response
Office of Inspection and Enforcement
U.S. Nuclear Regulatory Commission

FROM: Richard W. Krimm
Assistant Associate Director
Office of Natural and Technological Hazards Programs

SUBJECT: Catawba Nuclear Station Atomic Safety and Licensing Board (ASLB) Actions Related to Offsite Emergency Preparedness

References:

1. ASLB Supplemental Partial Initial Decision on Emergency Planning (ASLBP No. 81-463-06 OL) dated September 18, 1984.

2. Memorandum of October 29, 1984, from Jordan to Krimm, Subject: Catawba Atomic Safety and Licensing Board Actions Related to Offsite Preparedness.

3. Duke Power Company letter dated March 18, 1985, with the attached response to License Condition No. 23.

4. Memorandum of April 19, 1985, from Jordan to Krimm, Subject: Review of Duke Power Company Submittal For Catawba in Response to Facility Operating License Condition No. 23.

This is in response to your April 19, 1985 memorandum in which you requested that the Federal Emergency Management Agency (FEMA) review a response by the Duke Power Company to Item 2 in license condition No. 23 for the Catawba Nuclear Station. Item 2 in license condition No. 23 pertains to the content of warning signs and decals to be installed in the emergency planning zone.

FEMA has reviewed the revised wording for the signs and decals as provided in the March 18, 1985 letter from Hal B. Tucker to Harold R. Denton. The revised wording complies with the conditions stipulated by the Atomic Safety and Licensing Board and is, therefore, now acceptable.

If you have any questions on the above, please contact Mr. Robert S. Wilkerson, Chief, Technological Hazards Division, at 287-0200.

APPENDIX J

MAY 15, 1985, MEMORANDUM FROM FEMA

Federal Emergency Management Agency

Washington, D.C. 20472

MAY 15 1985

MEMORANDUM FOR: Edward L. Jordan
Director, Division of Emergency Preparedness and Engineering Response
Office of Inspection and Enforcement
U.S. Nuclear Regulatory Commission

FROM: Richard W. Krimm
Assistant Associate Director
Office of Natural and Technological Hazards Programs

SUBJECT: Catawba Nuclear Station Atomic Safety and Licensing Board (ASLB) Actions Related to Offsite Emergency Preparedness

References:

1. ASLB Supplemental Partial Initial Decision on Emergency Planning (ASLBP No. 81-463-06 OL) dated September 18, 1984.

2. Memorandum of October 29, 1984, from Jordan to Krimm, Subject: Catawba Atomic Safety and Licensing Board Actions Related to Offsite Preparedness.

3. Duke Power Company letter dated March 18, 1985, with the attached response to License Condition No. 23.

4. Memorandum of April 19, 1985, from Jordan to Krimm, Subject: Review of Duke Power Company Submittal For Catawba in Response to Facility Operating License Condition No. 23.

5. Memorandum of April 30, 1985, from Krimm to Jordan, Subject: Catawba Nuclear Station Atomic Safety and Licensing Board (ASLB) Actions Related to Offsite Emergency Preparedness.

This is in response to references 2 and 4 in which you requested that the Federal Emergency Management Agency (FEMA) verify completion of the four licensing conditions and two confirmatory items related to offsite emergency preparedness. First, in regard to the four licensing conditions:

Item 1. The Catawba Nuclear Station Emergency Planning Information Brochure, 1985 edition, as well as the Duke Power Company letter dated March 18, 1985, have been reviewed. The language of the public information brochure does, indeed, state directly that "high levels of radiation are harmful to health and may be life threatening." This statement is contained within the section of the brochure that deals with actions to be taken in the event of an emergency. Therefore, it is the opinion of FEMA that this licensing condition has been satisfied.

Item 2. This item was answered in the affirmative in reference 5.

Item 3. Attachments A and B to reference 3 contain the wording of the warning signs and decals which notify transients as to where they can obtain local emergency information. These attachments have been reviewed and are considered to be in compliance with the ASLB order.

Item 4. The attachments to reference 3 indicate the kinds of locations wherein the warning signs and decals and emergency response information will be placed and a sample letter used in the distribution of the brochures. FEMA is of the opinion that this licensing condition has been met.

Item 5. Attachment D to reference 3 consists of "Procedures for Carowinds Theme Park Evacuation for Catawba Nuclear Station." Attachment D has been reviewed by FEMA Region IV staff. In the opinion of FEMA, this document complies with the requirements of the ASLB order.

In regard to the two confirmatory items:

Item 1. FEMA Region IV staff confirmed in a telephone call to Mr. Buddy Jackson of the North Carolina Division of Emergency Management that additional training in radiological monitoring and decontamination had been provided to 25 persons in Gaston County, North Carolina during the month of January 1985. The instructor for the training course was Mr. George C. Ross.

Item 2. FEMA Region IV staff has reviewed revisions dated November 1984 to the South Carolina Emergency plan. These changes show the role and responsibilities of the Division of Public Safety in the Office of the Governor of South Carolina in ordering evacuations along with the identification of key individuals by title. These revisions, in the opinion of FEMA, comply with the ASLB order of September 18, 1984.

In our opinion, the license conditions have been met and the confirmatory items have been satisfactorily completed. If you have any questions on the above, please contact Mr. Robert S. Wilkerson, Chief, Technological Hazards Division, at 287-0200.

APPENDIX K

SEPTEMBER 1985 REPORT FROM EG&G IDAHO, INC.,
"CONFORMANCE TO GENERIC LETTER 83-28, ITEMS 3.1.3 AND 3.2.3"

CONFORMANCE TO GENERIC LETTER 83-28
ITEMS 3.1.3 AND 3.2.3
CATAWBA NUCLEAR STATION, UNIT NOS. 1 AND 2
DONALD C. COOK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2,
WILLIAM B. MCGUIRE NUCLEAR STATION, UNIT NOS. 1 AND 2,
SEQUOYAH NUCLEAR PLANT, UNIT NOS. 1 AND 2

R. VanderBeek
R. Haroldsen

Published September 1985

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 No. D6001

ABSTRACT

This EG&G Idaho, Inc. report provides a review of the submittals for several nuclear plants for conformance to Generic Letter 83-28, Items 3.1.3 and 3.2.3. The specific plants selected were reviewed as a group because of similarity in type and applicability of the review items. The group includes the following plants:

Plant	Docket Number	TAC Number
Catawba 1	50-413	57739, 57723
Catawba 2	50-414	
Cook 1	50-315	52989, 53827
Cook 2	50-316	52990, 53828
McGuire 1	50-369	53014, 53853
McGuire 2	50-370	53015, 53854
Sequoyah 1	50-327	53043, 53882
Sequoyah 2	50-328	53044, 53883

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 conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of System Integration by EG&G Idaho, Inc., NRC Licensing Support Section.

The U.S. Nuclear Regulatory Commission funded the work under the authorization, B&R 20-19-19-11-3, FIN No. D6001.

CONTENTS

TABLES

CONFORMANCE TO GENERIC LETTER 83-28

ITEMS 3.1.3 AND 3.2.3

CATAWBA NUCLEAR STATION, UNIT NOS. 1 AND 2

DONALD C. COOK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2,

WILLIAM B. MCGUIRE NUCLEAR STATION, UNIT NOS. 1 AND 2,

SEQUOYAH NUCLEAR PLANT, UNIT NOS. 1 AND 2

1. INTRODUCTION

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

This report documents the EG&G Idaho, Inc. review of the submittals from Catawba Nuclear Station, Unit Nos. 1 and 2, Donald C. Cook Nuclear Power Plant, Unit Nos. 1 and 2, William B. McGuire Nuclear Station, Units Nos. 1 and 2, and Sequoyah Nuclear Plant, Unit Nos 1, and 2 for conformance to Items 3.1.3 and 3.2.3 of Generic Letter 83-28. The submittals from the licensees utilized in these evaluations are referenced in Section 9 of this report.

These review results are applicable to the group of nuclear plants previously identified because of their similarity. These plants are similar in the following respects.

1. They are operating W-PWR reactors

2. They utilize ice condenser containment design

3. They are four loop reactors

4. They utilize solid state logic in the Plant Protective System

5. They utilize two class 1E Power System Trains.

An item of concern identified for any one of these plants is assumed to be potentially significant for all of the plants in the group.

2. REVIEW REQUIREMENTS

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

3. GROUP REVIEW RESULTS

The relevant submittals from each of the named reactor plants were reviewed to determine compliance with Items 3.1.3 and 3.2.3 of the Generic Letter. First, the submittals from each plant were reviewed to determine that these two items were specifically addressed. Second, the submittals were checked to determine if any post-maintenance test items specified by the technical specifications were identified that were suspected to degrade rather than enhance safety. Last, the submittals were reviewed for evidence of special conditions or other significant information relating to the two items of concern. The results of this review are summarized for each plant in Table 1.

In responses for Catawba 1 and 2, McGuire 1 and 2, and Sequoyah 1 and 2 (for Item 3.1.3) the licensees indicated that there had been no items identified relating to post-maintenance testing that could be demonstrated to degrade rather than enhance safety. However, the licensees gave no insight on the depth of review conducted for these two items.

TABLE 1.

Plants	Were Items 3.1.3 and 3.2.3 Addressed in the Submittal	Licensee Findings	Acceptable	Comments
Catawba 1 and 2	Yes	--	Yes	--
Cook 1 and 2	Yes	--	No	The licensee has not addressed the concerns of items 3.1.3 and 3.2.3.
McGuire 1 and 2	Yes	--	Yes	--
Sequoyah 1 and 2	Yes	--	3.1.3 Yes 3.2.3 No	The licensee addressed the concerns of items 3.1.3 but not 3.2.3.

4. REVIEW RESULTS FOR CATAWBA NUCLEAR STATION, UNIT NOS. 1 AND 2

4.1 Evaluation

Duke Power Company, the licensee for Catawba Nuclear Station, Unit Nos. 1 and 2 provided responses to Items 3.1.3 and 3.2.3 of Generic Letter 83-28 on November 4, 1983.[3] Within the responses, the licensee states that there is no knowledge of any post-maintenance testing requirements within the technical specifications which can be demonstrated to degrade safety of the reactor trip system or other safety-related components.

4.2 Conclusion

Based on the licensee's statement that no items have been identified in the Technical Specifications that degrade safety, the staff concludes that the licensee's response is adequate and acceptable.

5. REVIEW RESULTS FOR DONALD C. COOK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2

5.1 Evaluation

Indiana and Michigan Electric Company, the licensee for Donald C. Cook Nuclear Power Plant, Unit Nos. 1 and 2, provided initial responses to Items 3.1.3 and 3.2.3 of Generic Letter 83-28 on November 4, 1983.[4] Additional information for Items 3.1.3 and 3.2.3 was provided on April 10, 1985.[5] Neither of these submittals addressed the concerns of Items 3.1.3 and 3.2.3.

5.2 Conclusion

The licensee shall review the post-maintenance testing requirements contained within their technical specifications for the reactor trip system and other safety-related components and determine whether any current post-maintenance testing requirements may degrade rather than enhance safety. If any current post-maintenance testing requirements are identified that may degrade safety, the licensee shall identify these and submit a schedule for the submission of proposed revisions. If none are currently found to exist, a statement to that effect should be submitted.

6. REVIEW RESULTS FOR WILLIAM B. MCGUIRE NUCLEAR STATION, UNIT NOS. 1 AND 2

6.1 Evaluation

Duke Power Company, the licensee for William B. McGuire Nuclear Station, Unit Nos. 1 and 2, provided responses to Items 3.1.3 and 3.2.3 of Generic Letter 83-28 on November 4, 1983.[6] Within the resposes, the licensee states that there is no knowledge of any post-maintenance testing requirements within the technical specifications which can be demonstrated to degrade safety of the reactor trip system or other safety-related components.

6.2 Conclusion

Based on the licensee's statement that no items have been identified in the Technical Specifications that degrade safety, the staff concludes that the licensee's response is adequate and acceptable.

7. REVIEW RESULTS FOR SEQUOYAH NUCLEAR PLANT, UNIT NOS. 1 AND 2

7.1 Evaluation

The Tennesee Valley Authority, the licensee for the Sequoyah Nuclear Plant, Unit Nos. 1 and 2, provided responses to Items 3.1.3 and 3.2.3 of Generic Letter 83-28 on November 7, 1983.[7] For Item 3.1.3, the licensee states that, at the present time, no post-maintenance testing requirements have been identified which degrade rather than enhance safety. The licensee has not addressed the concerns of Item 3.2.3.

7.2 Conclusion

Based on the licensee's statement that they have not identified any requirements for past-maintenance testing of Reactor Trip System components in their Technical Specifications that may degrade rather than enhance safety, we find the licensee's response to Item 3.1.3 acceptable.

For Item 3.2.3, the licensee shall review the post-maintenance testing requirements contained in the technical specifications for other safety related components and determine whether any current post-maintenance requirements may degrade rather than enhance safety. If any current post-maintenance testing requirements are identified that may degrade safety, the licensee shall identify them. If no such requirements are found to exist, then a statement to that effect should be submitted.

8. GROUP CONCLUSION

The staff finds the response for Catawba 1 and 2 and McGuire 1 and 2 acceptable for both Items 3.1.2 and 3.2.3. The response for Sequoyah 1 and 2 is acceptable for Item 3.1.3 but not 3.2.3. The response for Cook 1 and 2 is not acceptable.

9. REFERENCES

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

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

3. Duke Power Company letter to NRC, H. B. Tucker to D. G. Eisenhut, Director, Division of Licensing, NRC, "Catawba Nuclear Station, Docket Nos. 50-413, 50-414," November 4, 1983.

4. Indiana and Michigan Electric Company letter to NRC, M. P. Alexich to D. G. Eisenhut, Director, Division of Licensing, NRC, "Donald C. Cook Nuclear Plant Unit Nos. 1 and 2, Docket Nos. 50-315 and 50-316, Licensee Nos. DPR-58 and DPR-74, Generic Letter 83-28, Required Actions Based on Generic Implications of Salem ATWS Events," November 4, 1983, AEP: NRC: 0838A

5. Indiana and Michigan Electric Company letter to NRC, M. P. Alexich to H. R. Denton, Director, Office of Nuclear Reactor Regulation, NRC, "Donald C. Cook Nuclear Plant Unit Nos. 1 and 2, Docket Nos. 50-315 and 50-316, Licensee Nos. DPR-58 and DPR-74, Generic Letter 83-28, Additional Information Requested in Response to Generic Letter 83-28," April 10, 1985, AEP: NRC: 0838H

6. Duke Power Company letter to NRC, H. B. Tucker to D. G. Eisenhut, Director, Division of Licensing, NRC, "McGuire Nuclear Station, Docket Nos. 50-369, 50-370," November 4, 1983.

7. Tennessee Valley Authority letter to NRC, L. M. Mills to E. Adensam, Chief, Licensing Branch No. 4, Division of Licensing, NRC, "Response to D. G. Eisenhut's July 8, 1983 letter to 'all licensees...;" November 7, 1983.

APPENDIX L

DECEMBER 1985 REPORT FROM EG&G IDAHO, INC.,
"CONFORMANCE TO REGULATORY GUIDE 1.97
CATAWBA NUCLEAR STATION, UNIT NOS. 1 AND 2"

CONFORMANCE TO REGULATORY GUIDE 1.97
CATAWBA NUCLEAR STATION, UNIT NOS. 1 AND 2

J. W. Stoffel

EGG-EA-6973
Published December 1985

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 No. A6493

ABSTRACT

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

FOREWORD

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

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

Docket Nos. 50-413 and 50-414

CONTENTS

CONFORMANCE TO REGULATORY GUIDE 1.97

CATAWBA NUCLEAR STATION, UNIT NOS. 1 and 2

1. INTRODUCTION

On December 17, 1982, Generic Letter No. 82-33 (Reference 1) was issued by D. G. Eisenhut, Director of the Division of Licensing, Nuclear Reactor Regulation, to all licensees of operating reactors, applicants for operating licenses and holders of construction permits. This letter included additional clarification regarding Regulatory Guide 1.97, Revision 2 (Reference 2) relating to the requirements for emergency response capability. These requirements have been published as Supplement No. 1 to NUREG-0737, "TMI Action Plan Requirements" (Reference 3).

Duke Power Company, the licensee for the Catawba Nuclear Station, Unit Nos. 1 and 2, provided a response to the Regulatory Guide 1.97 portion of the generic letter on September 26, 1983 (Reference 4). Additional information was submitted on October 22, 1985 (Reference 5).

This report provides an evaluation of these submittals.

2. REVIEW REQUIREMENTS

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

1. Instrument range

2. Environmental qualification

3. Seismic qualification

4. Quality assurance

5. Redundance and sensor location

6. Power supply

7. Location of display

8. Schedule of installation or upgrade

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

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

3. EVALUATION

The licensee provided a response to NRC Generic Letter 82-33 on September 26, 1983 and additional information on October 22, 1985. This evaluation is based on those submittals.

3.1 Adherence to Regulatory Guide 1.97

The licensee stated that their submittal provides a detailed account of the conformance of the Catawba Nuclear Station, Unit Nos. 1 and 2, to the recommendations of Revision 2 to Regulatory Guide 1.97. The licensee further states that the information provided in their submittal meets the requirements of Supplement No. 1 to NUREG-0737, Section 6. The licensee will complete any modifications they have identified to provide compliance with Regulatory Guide 1.97 by the end of the second refueling outage for Unit No. 1 and the end of the first refueling outage for Unit No. 2. Therefore, we conclude that the licensee has provided an explicit commitment on conformance to Regulatory Guide 1.97. Exceptions to and deviations from the regulatory guide are noted in Section 3.3.

3.2 Type A Variables

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

1. Reactor coolant system (RCS) pressure

2. Core exit temperature

3. RCS hot leg water temperature

4. RCS cold leg water temperature

5. Pressurizer level

6. Degrees of subcooling

7. Steam generator narrow range level

8. Steamline pressure

9. Refueling water storage tank level

This instrumentation meets the Category 1 recommendations consistent with the requirements for Type A variables, except as noted in Section 3.3.

3.3 Exceptions to Regulatory Guide 1.97

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

3.3.1 RCS Soluble Boron Concentration

Regulatory Guide 1.97 recommends a range of 0 to 6000 PPM for this variable. The licensee has instrumentation that covers a range of 0 to 5000 PPM. The justification given by the licensee for this deviation is that the range provided is adequate to read any anticipated concentrations of boron.

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

3.3.2 RCS Cold Leg Water Temperature

The instrumentation provided for this variable has a range of 0 to 700°F rather than 50 to 750°F as recommended by Regulatory Guide 1.97, Revision 2.

Regulatory Guide 1.97, Revision 3, May 1983 (Reference 6) recommends a range of 50 to 700°F for this variable. The instrumentation supplied by the licensee meets this range. Therefore, this is an acceptable deviation.

The licensee also takes exception to the redundancy recommended by Regulatory Guide 1.97 for this instrumentation. All four thermocouples feed into the same channel of the process control system (PCS) and are powered from the associated Class 1E bus. The justification provided by the licensee is that diversity is provided by the hot leg resistance temperature detectors, the incore thermocouples and steam pressure instrumentation.

Based on the alternate instrumentation available as a backup for this variable, we conclude that the instrumentation supplied for this variable is adequate and, therefore, acceptable.

3.3.3 RCS Hot Leg Water Temperature

The instrumentation provided for this variable has a range of 0 to 700°F rather than 50 to 750°F as recommended by Regulatory Guide 1.97, Revision 2.

Regulatory Guide 1.97, Revision 3, recommends a range of 50 to 700°F for this variable. The instrumentation supplied by the licensee meets this range. Therefore this is an acceptable deviation.

3.3.4 Containment Sump Water Level (Narrow Range)

Regulatory Guide 1.97 recommends Category 2 justification for this variable. The licensee has provided Category 3 instrumentation. The licensee considers the qualified wide range instrumentation to be the key variable with the narrow range as a backup. The narrow range instrumentation has no intended accident or post-accident monitoring function, therefore, Category 3 instrumentation is considered adequate by the licensee.

The Category 1 wide range instruments cover the entire range of expected water levels for post-accident conditions and no post-accident functions rely on this narrow range instrumentation. Therefore, we conclude that the Category 3 backup narrow range instrumentation is acceptable for this variable.

3.3.5 Radiation Level in Circulating Primary Coolant

The licensee has one channel of primary coolant radiation level instrumentation on the letdown line. Additional information on the radiation level in the circulating primary coolant is provided by analysis of the post-accident sampling system samples. The post-accident sampling system is being reviewed by the NRC as part of their review of NUREG-0737, Item II.B.3.

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

3.3.6 Residual Heat Removal (RHR) Heat Exchanger Outlet Temperature

Regulatory Guide 1.97 recommends a range of 32 to 350°F for this variable. The range provided is 50 to 400°F. The justification given by the licensee for this deviation is that the installed range is suited to the operating and accident temperatures expected in the residual heat removal system at this station. Based on this statement, we find the provided range acceptable.

Documentation is not available to verify the instrumentation will withstand the anticipated maximum post-accident recirculation radiation dose for its location. This information is being researched for this instrumentation. A commitment has been made to replace this instrumentation at the first refueling outage if it is found that its rating is not acceptable.

3.3.7 Accumulator Tank Level and Pressure

The licensee deviates from the recommended range and environmental qualification for this instrumentation.

The pressure range recommended by Regulatory Guide 1.97 is 0 to 750 psig. The indicated pressure range is 0 to 700 psig. The normal operating pressure of these tanks is 450 psig and is manually controlled. The existing pressure range adequately covers any expected accumulator pressure. Therefore this range is an acceptable deviation from Regulatory Guide 1.97.

The level range recommended by Regulatory Guide 1.97 is 10 to 90 percent volume. The indicated level range corresponds to approximately 23 to 95 percent of the accumulator tank volume. The existing range is adequate to verify safety injection or check valve leakage into the tank. Therefore the existing range is adequate to monitor accumulator operation at this station.

The installed pressure and level instrumentation does not meet the recommended environmental qualification (including radiation levels) for a post-accident situation.

The existing instrumentation is not acceptable. An environmentally qualified instrument is necessary to monitor the status of these tanks. The licensee should designate either level or pressure as the key variable to directly indicate accumulator discharge and provide instrumentation for that variable that meets the requirements of 10 CFR 50.49.

3.3.8 Pressurizer Level

The instrumentation installed for this variable has an indicated range that corresponds to from 5 to 95 percent volume. Regulatory Guide 1.97 recommends a range of bottom to top. The licensee justifies this deviation by stating that this range is consistent with Westinghouse requirements and it is considered to be adequate for the intended monitoring function.

We note that this range does not include the hemispherical ends of the vessel where the height/volume ratio is not linear. However, we find that the indicated range is sufficient to ensure proper operation of the pressurizer. This is an acceptable deviation from Regulatory Guide 1.97.

3.3.9 Quench Tank Level

The instrumentation installed for this variable has an indicated range from 3 to 97 percent volume. Regulatory Guide 1.97 recommends a range from top to bottom. The licensee states that the range of this instrumentation is adequate for the monitoring function.

We find that this deviation is minor. The installed range is sufficient to monitor the operation of this tank.

3.3.10 Quench Tank Temperature

The licensee has instrumentation for this variable that indicates 50 to 300°F. Regulatory Guide 1.97 recommends 50 to 750°F. The licensee has committed to expand this range, by the end of his first refueling outage, to 50 to 350°F. This instrumentation will then cover the limiting saturation temperatures including the tank rupture disk pressure of 100 psig. This new range will be adequate to monitor the operation of this tank. Therefore, this is an acceptable deviation from Regulatory Guide 1.97.

3.3.11 Wide Range Steam Generator Level

The licensee has steam generator level instrumentation with a range slightly less than that recommended by Regulatory Guide 1.97 (from tube sheet to separators). The instrumentation indicates from nine inches above the tube sheet to the separators.

The steam generator is, in effect, empty at nine inches above the tube sheet; therefore, this deviation is minor considering the total steam generator volume. The existing range is acceptable for this variable.

3.3.12 Steam Generator Pressure

Regulatory Guide 1.97 recommends a range of 0 to 20 percent above the lowest safety valve pressure relief setpoint for this variable. The licensee has provided instrumentation with a range of 0 to 1300 psig. This is 10 percent above the lowest safety valve setpoint and 6 percent above the highest safety valve setpoint. The licensee states, in Reference 5, that the existing range is adequate because the maximum system pressure during the worst postulated loss of heat sink accident is no greater than 1221 psig.

Based on the licensee's justification, we find the existing range adequate to monitor the steam generator pressure during all accident and post-accident conditions. Therefore, this is an acceptable deviation from Regulatory Guide 1.97.

3.3.13 Containment Sump Water Temperature

The licensee does not provide instrumentation for this variable. The justification given by the licensee is that this variable is not used in the management of a design basis accident.

In Reference 5, the licensee provided the following justification and identified alternate instrumentation to monitor this variable.

1. The available net positive suction head (NPSH) for the Residual Heat Removal pumps is conservatively calculated with a sufficient safety margin such that an indication of sump temperature is not required in order to insure adequate NPSH.

2. No automatic or manual actions are initiated based on this temperature.

3. For containment cooling, containment pressure is the variable of primary importance. Alternate indications of containment cooling status is provided by containment atmosphere temperature and containment spray flow.

4. An alternate temperature indication for long term operation in cold leg recirculation is provided by residual heat removal heat exchanger inlet temperature.

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

3.3.14 Makeup Flow-In
Letdown Flow-Out

The licensee has provided Category 3 instrumentation for these variables. Regulatory Guide 1.97 recommends Category 2 instrumentation for these variables. The instrumentation is located in a mild temperature environment but is not rated to withstand the anticipated maximum design-basis accident radiation dose for the installed location. This instrumentation is not used in the mitigation of accidents in which harsh environments are a result and is automatically isolated upon an engineered safety features (ESF) actuation. The licensee therefore states that the installed instrumentation is adequate for the intended monitoring function.

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

3.3.15 Volume Control Tank Level

Regulatory Guide 1.97 recommends instrumentation for this variable that reads from the top to the bottom of the tank. The instrumentation at this station covers the linear portion of the tank (approximately 17 to 82 percent of the volume). Extending the range into the domed portions of the tank would result in nonlinear readings at each end of the scale.

The existing level range is adequate, as the minimum and maximum levels are maintained within this range. Therefore, this is an acceptable deviation from Regulatory Guide 1.97.

3.3.16 High Level Radioactive Liquid Tank Level

Regulatory Guide 1.97 recommends instrumentation for this tank that reads from the top to the bottom. The indicated range for this variable corresponds to approximately 2 to 90 percent. The existing range is adequate to monitor the operation of this tank. Therefore, this is an acceptable deviation from Regulatory Guide 1.97.

3.3.17 Emergency Ventilation Damper Position

The licensee states that all emergency ventilation dampers whose failure could result in an atmospheric release, as a result of an actuation during an accident, have the required indiction in the control room. For other system dampers, where failure would not result in an atmospheric release, indication of system alignment is determined by system pressures and flow.

These diverse methods of determining damper position meet the intent of Regulatory Guide 1.97. We find this instrumentation acceptable.

3.3.18 Area Radiation (Radiation Exposure Rate)

Revision 2 of Regulatory Guide 1.97 recommends Category 2 radiation exposure rate monitors. Revision 3 of Regulatory Guide 1.97 changes the recommended instrumentation to Category 3. The category of the instrumentation provided is within the guidance of Regulatory Guide 1.97, Revision 3 and is therefore acceptable.

The recommended range (10^{-1} to 10^{4} R/hr) is met only in the area adjacent to the reactor coolant filters. All the other instruments for this variable have a range of 10^{-1} to 10^{4} mR/hr. The justification provided by the licensee for this deviation is that this range is intended for personnel protection. The other regulatory guide functions are performed through health physics procedures using portable survey equipment, with supplemental information provided by the effluent process radiation monitoring system.

From a radiological standpoint, if the radiation levels reach or exceed the upper limit of the range, personnel would not be permitted into the areas without portable monitoring (except for life saving). Based on the alternate instrumentation used by the licensee for this variable, we find the proposed ranges for the radiation exposure rate monitors acceptable.

3.3.19 Plant Airborne and Area Radiation (Sampling With Onsite Analysis, Portable Instrumentation)

The licensee has grouped the following variables from Regulatory Guide 1.97 under this heading. (a) all identified plant release points,

(b) airborne radiohalogens and particulates, (c) plant and environs radiation, (d) plant and environs radioactivity. The licensee states that some of this instrumentation has ranges which differ from the recommendations of Regulatory Guide 1.97. However, the instrumentation has been selected using the considerations shown in their FSAR, Section 12.5 (Reference 7).

Section 12.5.2.1 of the licensee's FSAR states, pertaining to portable and laboratory equipment and instrumentation, that it was selected to provide appropriate detection capabilities, ranges, sensitivities, and accuracies needed for anticipated radiation types and the expected radiation levels.

We consider this a commitment that these variables will be adequately monitored. The existing ranges were not submitted in Reference 4. Reference 5 provided the instrument ranges as required by Section 6.2 of NUREG-0737, Supplement No. 1.

3.3.20 Wind Speed

Regulatory Guide 1.97, Revision 2 recommends a range of 0 to 67 mph for this variable. The licensee's instrumentation has a range of 0 to 60 mph. The licensee states that this range is adequate for their meteorological conditions.

Regulatory Guide 1.97, Revision 3, recommends a range of 0 to 50 mph for this variable. The instrumentation exceeds this recommendation and is acceptable.

4. CONCLUSIONS

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

1. Accumulator tank level and pressure--the licensee should provide a level or pressure instrument for this variable that is environmentally qualified in accordance with 10 CFR 50.49 (Section 3.3.7).

5. REFERENCES

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

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

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

4. Duke Power Company letter, Hal B. Tucker to H. R. Denton, Director, Office of Nuclear Reactor Regulation, NRC, September 26, 1983.

5. Duke Power Company letter, Hal B. Tucker to H. R. Denton, Director, Office of Nuclear Reactor Regulation, NRC, "Catawba Nuclear Station," October 22, 1985.

6. Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following and Accident, Regulatory Guide 1.97, Revision 3, NRC, Office of Nuclear Regulatory Research, May 1983.

7. Final Safety Analysis Report, Catawba Nuclear Station, Revision 7, dated February 22, 1983, Section 12.5.

37429

APPENDIX M

OCTOBER 8, 1985, MEMORANDUM FROM FEMA

Federal Emergency Management Agency

Washington, D.C. 20472

Mr. William J. Dircks
Executive Director for Operations
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

OCT 8 1985

Dear Mr. Dircks:

In accordance with the Federal Emergency Management Agency (FEMA) rule 44 CFR 350, the State of South Carolina submitted its State and local plans for radiological emergencies related to the Catawba Nuclear Station to the Regional Director of FEMA Region IV for FEMA's review and approval on September 5, 1984; and the State of North Carolina submitted its State and local plans for radiological emergencies related to the Catawba Nuclear Station to the Regional Director of FEMA Region IV for FEMA's review and approval on August 31, 1984. The Regional Director forwarded his evaluation of the State and local plans to me on November 20, 1984, in accordance with section 350.11 of the rule. His submission included an evaluation of the full-participation exercise conducted on February 15-16, 1984, and a report of the public meeting held on February 17, 1984, which explained the site-specific aspects of the State and local plans.

The alert and notification system (ANS) for the Catawba Nuclear Station is under review. An engineering design review has been completed and the telephone survey of the public was conducted immediately following the alert and notification system demonstration on May 7, 1985. The results of the demonstration are currently being evaluated. FEMA is still awaiting submittal of acceptable siren system operability results in accordance with section E.6.2.1 of FEMA-43. I will advise you of the adequacy of this ANS once the review is complete.

Based on an overall evaluation, I find and determine that, subject to the condition stated below, the South Carolina and North Carolina State and local plans and preparedness for the Catawba Nuclear Station are adequate to protect the health and safety of the public in that there is reasonable assurance that the appropriate protective measures can be taken in the event of a radiological emergency. However, while there is an alerting and notification (ANS) system in place and operational, this approval is conditional on FEMA's verification of the ANS in accordance with the criteria in NUREG-0654/FEMA REP-1, Rev. 1, Appendix 3 and in FEMA-43, "Standard Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants."

Sincerely,

Samuel W Speck

Samuel W. Speck
Associate Director
State and Local Programs
and Support

NRC FORM 335 (7-77)

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

1. REPORT NUMBER (Assigned by DDC)
NUREG-0954
Supplement No. 5

2. (Leave blank)

3. RECIPIENT'S ACCESSION NO.

4. TITLE AND SUBTITLE (Add Volume No., if appropriate)
Safety Evaluation Report related to the operation of Catawba Nuclear Station, Units 1 and 2

5. DATE REPORT COMPLETED

MONTH	YEAR
February	1986

7. AUTHOR(S)

DATE REPORT ISSUED

MONTH	YEAR
February	1986

9. 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

6. (Leave blank)

8. (Leave blank)

12. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)

Same as 9 above

10. PROJECT/TASK/WORK UNIT NO.

11. CONTRACT NO.

13. TYPE OF REPORT
Safety Evaluation Report, Supplement 5

PERIOD COVERED (Inclusive dates)

15. SUPPLEMENTARY NOTES
Pertains to Docket Nos. 50-413 and 50-414

14. (Leave blank)

16. ABSTRACT (200 words or less)

This report supplements the Safety Evaluation Report (NUREG-0954) issued in February 1983 by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission with respect to the application filed by Duke Power Company, North Carolina Municipal Power Agency Number 1, North Carolina Membership Corporation, Saluda River Electric Cooperative, Inc., and Piedmont Municipal Power Agency as applicants and owners for licenses to operate the Catawba Nuclear Station, Units 1 and 2 (Docket Nos. 50-413 and 50-414, respectively). The facility is located in York County, South Carolina, approximately 9.6 km (6 mi) north of Rock Hill and adjacent to Lake Wylie. This supplement provides additional information supporting the license for initial criticality and power ascension to full-power operation for Unit 2.

17. KEY WORDS AND DOCUMENT ANALYSIS

17a. DESCRIPTORS

17b. IDENTIFIERS/OPEN-ENDED TERMS

18. AVAILABILITY STATEMENT
Unlimited

19. SECURITY CLASS (This report)
Unclassified

20. SECURITY CLASS (This page)
Unclassified

21. NO. OF PAGES

22. PRICE
$

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

120555078877 1 1AN
US NRC
ADM-DIV OF TIDC
POLICY & PUB MGT BR-PDR NUREG
W-501
WASHINGTON DC 20555