8005160465

NUREG-0517
Supp. No. 4

U. S. Nuclear
Regulatory Commission

Safety Evaluation Report

related to operation of

Salem Nuclear Generating Station, Unit 2

Public Service Electric and Gas Company, et al.

Supplement No. 4

Office of Nuclear Reactor Regulation

Docket No. 50-311

April 1980

Available from

GPO Sales Program
Division of Technical Information and Document Control
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

and

National Technical Information Service
Springfield, Virginia 22161

NUREG-0517
Supplement No. 4
April 18, 1980

SUPPLEMENT NO. 4

TO THE

SAFETY EVALUATION REPORT

BY THE

OFFICE OF NUCLEAR REACTOR REGULATION

U. S. NUCLEAR REGULATORY COMMISSION

IN THE MATTER OF

PUBLIC SERVICE ELECTRIC AND

GAS COMPANY, ET AL.

SALEM NUCLEAR GENERATING STATION

UNIT 2

DOCKET NO. 50-311

FOREWORD

Supplement No. 4 to the Safety Evaluation Report for Salem Nuclear Generating Station, Unit 2 consists of two parts:

PART I - Review and Evaluation of Non-TMI-2 Issues.

PART II - Review and Evaluation of TMI-2 Issues Related to Fuel Load and Low Power Test Program.

TABLE OF CONTENTS

PART I

NON-TMI-2 ISSUES

PAGE

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

APPENDICES

PART I

1.0 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

On October 11, 1974, the Nuclear Regulatory Commission (Commission) issued its Safety Evaluation Report regarding the application by the Public Service Electric and Gas Company, the Philadelphia Electric Company, the Delmarva Power and Light Company, and the Atlantic City Electric Company (applicants) for licenses to operate the Salem Nuclear Generating Station, Units 1 and 2 (Salem Units 1 and 2). The Safety Evaluation Report was supplemented by Supplement Nos. 1 through 3 which documented the resolution of several outstanding issues.

On August 13, 1976, Facility Operating License DPR-70 was issued for Salem Unit 1. The license permitted Unit 1 to operate at 100 percent power. The unit was placed in commercial operation on June 30, 1977.

Since the time that Salem Unit 1 was permitted to operate at 100 percent power, there have been changes in the NRC requirements, new licensing guidance has been put into effect, changes have been made on the design of the plant, additional experience has been gained at Salem Unit 1 as well as other pressurized water reactors and the Three Mile Island (TMI-2) accident occurred. As a result, we have requested, and the applicants have provided additional information regarding the facility.

Following the TMI-2 accident, the Commission "paused" in its licensing activities to assess the impact of TMI-2. During this "pause", the recommendations of several groups established to investigate the lessons learned from TMI-2 became available. These groups included the Presidential Commission to Investigate TMI-2, the NRC Special Inquiry Group and several staff task forces, such as the Lessons Learned Task Force and the Bulletins and Orders Task Force. All available recommendations were correlated and assimilated into a "TMI Action Plan Prerequisites for Resumption of Licensing."

The Commission has approved the prerequisites for authorizing Sequoyah Unit 1, to conduct Special Tests at power levels not exceeding five percent of full power. The Commission subsequently indicated that it would consider a similar authorization for Salem Unit 2.

This supplement addresses the requirements for fuel loading and conducting low power testing of Salem Unit 2 up to a power level of five percent of full power, and (1) identifies non-TMI-2 issues and their status since the issuance of the

Safety Evaluation Report through Supplement No. 3, and (2) discusses matters related to the TMI-2 accident. Each of the following sections of the supplement is numbered the same as the corresponding sections of the Safety Evaluation Report. Except where noted, this supplement is an addition to the discussion in the Safety Evaluation Report and the supplements thereto. Appendix A is a continuation of the chronology of our principal actions related to the processing of the application.

As stated in the Foreword, this supplement consists of two parts:

Part I - Review and Evaluation of Non-TMI-2 Issues.

Part II - Review and Evaluation of TMI-2 Issues Related to Fuel Load and Low Power Test Program.

1.7 Outstanding Issues

In Section 1.7 of Supplement No. 3 to the Safety Evaluation Report, we identified several outstanding issues which required resolution prior to a decision on issuance of an operating license for Salem Unit 2. The resolution or status of those issues is discussed in this supplement.

In Section 1.8 of Supplement No. 3 to the Safety Evaluation Report, we identified a number of items for which we had completed our review but required confirmatory information from the applicants. The conclusion or status of those items is discussed in this supplement.

Since that time, additional issues have been identified which required resolution prior to a decision on issuance of an operating license for Salem Unit 2. The resolution or status of these additional issues is also discussed in this supplement.

The remaining outstanding issues, which are listed below, have been acceptably resolved for the low power test program as discussed in the indicated sections of this supplement.

(1) We require that the applicants complete their analysis of piping in response to IE Bulletin No. 79-07, "Seismic Stress Analysis of Safety Related Piping," (Section 3.7.1).

(2) We require that the applicants reassess their environmental qualification documentation in accordance with the guidelines in NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment" (Section 3.11).

(3) We have not completed our review of the detailed evaluation provided regarding a restriction in the use of the Westinghouse PAD-3.3 Code (Secton 4.2.2).

(4) We require that the applicants provide revised emergency operating procedures relating to postulated anticipated transients without scram (Section 7.2.2).

(5) We require that the applicants provide information relating to IE Bulletin No. 79-27, "Loss of Non-Class IE Instrumentation and Control Power System Bus During Operation" (Section 7.9).

(6) We have not completed our review of the information submitted by the applicants regarding long term reliability of the diesel generators (Section 8.3.4).

(7) We require that the applicants commit to provide prompt responses to additional information requirements regarding our review of Westinghouse transient anslysis codes dealing with steam line and feedline break accidents (Section 15.1.1).

(8) We have not completed our re-review of the applicants' "Q-list" (Section 17.1).

1.9 Unresolved Safety Issues

On November 23, 1977, the Atomic Safety and Licensing Appeal Board issued a decision (ALAB-444) in connection with its consideration of the application for the River Bend Station, Unit Nos. 1 and 2 (Docket Nos. 50-458 and 50-459) which established specific requirements for addressing unresolved generic safety issues in connection with our licensing proceedings. Those requirements are applicable to the Salem Unit 2 application.

Appendix C to Part 1 of this supplement presents information for the Salem Unit 2 application in conformance with the Appeal Board decision enunciated in ALAB-444.

3.0 DESIGN CRITERIA - STRUCTURES, COMPONENTS, EQUIPMENT AND SYSTEMS

3.5 Missile Protection Criteria

3.5.2 Tornado Missiles

In Section 3.5.2 of Supplement No. 3 to the Safety Evaluation Report, we concluded that, subject to confirmatory information that the applicants have adequately demonstrated that they can provide sufficient auxiliary feedwater to achieve cold shutdown in the event of a tornado missile strike, Salem Unit 2 has been designed and constructed to withstand the effects of tornado generated missiles.

In a letter dated March 6, 1979, the applicants provided additional confirmatory information regarding the ability to line up and use the service water system which includes the installation of a spool piece. The applicants estimate that the time for obtaining control room indication of low water and the start of spool piece installation will not exceed 40 minutes. We judge this to be reasonably conservative since low water indication would occur at about the same time as the loss of water and since the spool piece is stored at the connection point.

The applicants have also demonstrated that two men can install the spool piece in 13 minutes. Hence we believe that the total estimated time of about 53 minutes (40 minutes to start and an additional 13 minutes to complete) between the loss of water and the completion of spool piece connection is reasonable. However, in order to assure that the connection capability is maintained throughout the lifetime of the plant, we will require (in the form of a Technical Specification) that the applicants demonstrate the availability and accessibility of the spool piece on an annual basis.

The applicants also have performed an analysis to determine the amount of time, following a loss of alternating current power and main and auxiliary feedwater flow, before the core begins to be uncovered. They estimate that the interval is about 70 minutes, as determined by the time it takes for the primary coolant to reach saturation temperature, the time for water boil-off until the core begins to uncover, and the time for losing the secondary heat sink (steam generators). We have reviewed the applicants' calculations and find that they are acceptable and that adequate margins are provided such that there is sufficient assurance that the core will not be uncovered during that time interval.

Thus we believe that the applicants have the capability of lining up the service water system to the auxiliary feedwater pumps in a time interval which assures that the core is adequately cooled in the event of loss of all normal water backup systems.

We have also reviewed the applicants' service water system in terms of vulnerability to tornado missiles and the ability to provide sufficient auxiliary feedwater to achieve cold shutdown in the event of a tornado missile strike, and find that it is adequately protected against the design basis tornado missiles since it is enclosed in tornado protected buildings and structures.

In conclusion, we find that the applicants have adequate assurance of a supply of water to meet the feedwater makeup requirements in the event of loss of all normal water backup systems due to tornado missile damage. (Section II.K.3 of Part II to this supplement discusses our generic review of the loss of auxiliary feedwater accidents for Westinghouse-designed plants. As indicated there, any system modifications resulting from our review, which are appropriate to Salem Unit 2, would be required for Salem Unit 2 prior to authorizing full power operation.)

3.7 Seismic Design

In Section 3.7 of Supplement No. 3 to the Safety Evaluation Report, we stated that we required the applicants to provide additional information regarding the seismic design as it relates to (1) a comparison of the response spectra and damping values between those currently adopted by us and those adopted by the applicants, (2) a justification for the use of a ± 10 percent peak width increment for the floor response spectra, (3) the criteria used for the selection of lumped masses, and (4) the criteria used for either coupling or decoupling a subsystem to its supporting system.

In letters dated January 18, 1979, January 21, 1979 and February 6, 1979, the applicants have provided the necessary additional information. We have reviewed the information provided by the applicants and the results of our review are discussed below.

With respect to the difference in response spectra and related damping values between those currently adopted by us and those adopted by the applicants, the applicants have provided a key comparison of the two criteria in their letter dated February 6, 1979. We have reviewed the comparison and agree that the response spectra and damping values used in the design of Salem Unit 2 will result in a design as conservative as one resulting from the use of the criteria identified in Regulatory Guide 1.60, "Design Response Spectra for Seismic Designs of Nuclear Power Plants," and Regulatory Guide 1.61, "Damping Values for Seismic Design of Nuclear Power Plants." Therefore, we consider this matter resolved.

With respect to floor response spectra peak broadening for seismic Category I structures, our requirements are as stated in Regulatory Guide 1.22, "Development of Floor Design Spectra for Seismic Design of Floor Supported Equipment or Components." This guide recommends that the effects of parameter variation on floor response spectra for soil sites can normally be accounted for by increasing the individual peak widths by ± 15 percent, if the effects of parameter variation on floor response spectra are not computed. The applicants used a ± 10 percent increment instead of the ± 15 percent increment recommended by the regulatory guide. The applicants have indicated that the containment floor response spectra were broadened by ± 10 percent since the prominent spike occurs at one cycle per second and none of the equipment frequencies falls in this area. For other seismic Category I buildings, there is more than one sharp spike in the floor response spectra. However, in order to avoid undesirable resonance effects, the components were stiffened and frequencies shifted outside the sharp spiked areas, thereby eliminating the broadening considerations. In flat areas of the response spectra, a 10 percent shifting of frequency coordinates was applied to obtain the equipment response. For these flat areas, we have determined that the use of a 10 percent shifting instead of a 15 percent shifting (a decrease of five percent) would not cause an appreciable change to equipment response. On this basis, we have concluded that the applicants' justification for use of a ± 10 percent peak broadening increment is acceptable and, therefore, consider this matter resolved.

The third issue relates to the criteria used for the selection of the number of lumped masses for the seismic system analysis. The applicants have stated in their response to our requests for additional information that they have complied with the modeling criteria required by Section 3.7.2 of the Standard Review Plan. Specifically, the applicants have stated that the introduction of additional degrees of freedom in their models will not result in more than 10 percent increase in the structural response. Therefore, we have determined that the applicants' modeling criteria are in compliance with Section 3.7.2 of the Standard Review Plan and, therefore, are acceptable.

With respect to the design control of fundamental frequencies of key subsystems, the applicants have stated that these frequencies were considered in relation to the dominant frequencies of the supporting systems and, in most design cases, the key subsystems were considered as decoupled from their supporting systems. We had transmitted to the applicants our acceptance criteria for either coupling or decoupling a subsystem to its supporting system and had requested that the applicants state whether they comply with the criteria. Specifically, the applicants stated that the fundamental frequencies of key subsystems were considered in relation to the dominant frequencies of their supporting systems and the subsystems that were analyzed/tested as decoupled systems from the supporting system have a mass ratio (of subsystem to that of the supporting system) of less than one percent. On this basis we have determined that the criteria used by the applicants regarding this matter are in accordance with our requirements and, therefore, are acceptable.

Based upon the information provided by the applicants, as delineated above and in Section 3.7 of Supplement No. 3 to the Safety Evaluation Report, we reaffirm the conclusion previously made in Section 3.7 of the Safety Evaluation Report, which is: the seismic design of the systems and subsystems, dynamic analysis method and procedures, and seismic instrumentation criteria are acceptable.

3.7.1 Seismic Stress Analysis of Safety Related Piping

Subsequent to the issuance of Supplement No. 3 to the Safety Evaluation Report, in the course of evaluation of certain piping designs for some plants, discrepancies were observed between the original piping analysis computer code used to analyze seismic loads and a currently acceptable computer code developed for this purpose. As a result, the Office of Inspection and Enforcement issued IE Bulletin No. 79-07, "Seismic Stress Analysis of Safety Related Piping," dated April 14, 1979, to all licensees and construction permit holders to inform them of the discrepancies and to request certain information regarding the analysis performed for their plants.

In a letter dated May 3, 1979, the applicants for Salem Unit 2 submitted their response to IE Bulletin No. 79-07. We have reviewed the information provided by the applicants and our evaluation of information submitted is as follows:

With respect to the primary loops (nuclear steam supply system), the applicants had analyzed the system in accordance with our requirements and we conclude that the system is acceptable. Therefore, the systems under discussion in this evaluation are in the balance of plant scope.

Subsequent to the receipt of IE Bulletin No. 79-07, the applicants reanalyzed 43 piping subsystems which comprise the entire Salem Unit 2 residual heat removal system and attached branch lines. These 43 analyses included piping of various configurations and diameters, and constituted a representative sample of the seismic Category I piping at Salem Unit 2. The reanalysis indicated that the original piping and support design of the residual heat removal system was sufficiently conservative to meet the design criteria with only minor changes. The changes will increase the available design margin in the piping systems to a level consistent with current standards. However, the systems could perform their function prior to modification, but with lower margin. The 43 piping subsystems already reanalyzed are expected to be typical of the Unit 2 piping and represent various complex piping configurations in which the effects of all three orthogonal earthquakes will be felt. Therefore, these 43 piping subsystems provide an adequate sample for estimating the effect of IE Bulletin No. 79-07 on the design of Salem Unit 2 piping.

Consequently, we believe that only a minimal number of hardware changes will be necessary to fully bring the Salem Unit 2 piping seismic design into compliance with the design criteria. As required by IE Bulletin No. 79-07 and subsequent IE Bulletin No. 79-14 "Seismic Analyses For As-Built Safety Related Piping Systems," dated July 2, 1979, as revised, the applicants have recently performed a walk-through inspection of the Unit 2 piping and compared the "as built" piping against its piping isometric drawings. Our Office of Inspection and Enforcement will verify that the Unit 2 piping analyses represent the "as built" condition.

To fully resolve the issues of IE Bulletin No. 79-07 for Salem Unit 2, we require that all affected piping systems, not just a sample, be reanalyzed and modified as necessary to meet current standards prior to commercial operation. In setting conditions for the performance of this reevaluation, we believe that low power operation can commence while the reevaluation is proceeding without affecting the health and safety of the public. Our requirements in this matter are as follows:

(1) The applicants must complete the reevaluation of all seismic Category I large bore piping (greater than two inches in nominal pipe diameter) and any small bore piping (two inches and less in nominal pipe diameter) essential to safe shutdown of the plant. We must approve this reevaluation and ascertain the need to complete certain required hardware changes prior to exceeding five percent power. This reevaluation includes not only piping stresses, but also support loads and stresses and a determination that pump and valve operability is not affected by any increased nozzle loads.

    Our justification for permitting operation during low power testing is that (1) the primary loops have been found acceptable, (2) the 43 piping subsystems which comprise the entire Unit 2 residual heat removal system have been reanalyzed and the results indicate that the original piping and support design of the residual heat removal system was sufficiently conservative to meet current licensing criteria with only minor changes and, (3) the likelihood of occurrence of a safe shutdown earthquake during this short period of time is small. In the unlikely event that a postulated safe shutdown earthquake should occur, we believe that at most only a few piping supports might be damaged, and that all systems would function as required to achieve a plant shutdown. Should the reanalysis require any significant hardware changes, we would require their implementation before approving continued operation.

(2) The applicants must complete the reevaluation of all remaining small bore piping and receive our approval prior to exceeding five percent power. Also, all required hardware changes for both large and small bore piping systems must be completed by that time.

    Our justification for permitting operation during low power testing is that these small bore lines are not critical to shutting the plant down. Additionally, the initial sample of 43 calculations indicate that the Unit 2 small bore lines are very conservatively designed and no hardware modifications are anticipated. Therefore, due to the initial sample calculations reaffirming the conservatism of the applicants' original design, we believe that our schedule provides reasonable assurance for the protection of the public's health and safety while the reevaluation is being completed.

3.7.2 <u>Incorrect Weights for Swing Check Valves Manufactured By Velan Engineering Corporation</u>

Subsequent to the issuance of Supplement No. 3 to the Safety Evaluation Report, the applicants were required by IE Bulletin No. 79-04, "Incorrect Weights for

Swing Check Valves Manufactured by Velan Engineering Corporation," dated March 30, 1979, to determine if the Salem Unit 2 piping seismic analyses had assumed the correct weights for any Velan swing check valves used. In its response to IE Bulletin No. 79-04, the applicants stated that the correct weights were originally used in most cases, and that the piping seismic analyses had been rerun in those cases where the incorrect valve weights were used. Therefore, we consider this matter to be resolved.

3.9 Mechanical Systems and Components

3.9.1 Effects of Asymmetric Loss-of-Coolant Loads on Primary Coolant System Components and Supports

In Section 3.9.1 of Supplement No. 3 to the Safety Evaluation Report, we stated that the applicants had evaluated the primary system components and supports for the effects of asymmetric loss-of-coolant accident loads and had submitted the results of their analysis related to the reator cavity. We also stated that we would report the results of our review of this matter in a supplement to the Safety Evaluation Report. Our evaluation has now been completed and the results are discussed below.

In response to our requests for additional information, the applicants had performed the detailed structural analyses by postulating several primary loop break locations within the primary coolant system. The specific break locations of the total required to be postulated by Section 3.6.2 of the Standard Review Plan, which are critical to the design of the reactor pressure vessel supports, are as follows:

(1) Reactor vessel inlet nozzle pipe break.

(2) Reactor vessel outlet nozzle pipe break.

(3) Reactor coolant pump outlet nozzle pipe break.

Pipe whip restraints are provided in the primary shield wall area to limit the displacement of the broken pipe such that the resulting break flow areas are less than those that would result from an unrestrained double ended pipe break. Pipe breaks at the hot and cold leg reactor vessel nozzles were postulated using a flow area of 76 and 100 square inches, respectively. Detailed studies have shown that pipe breaks at the hot or cold leg reactor vessel nozzles, even with a limited break area, would result in the highest reactor support loads and the highest vessel displacements, primarily due to the influence of reactor cavity pressurization. For completeness a break outside the shield wall, for which there is no cavity pressurization, was also analyzed; specifically the pump outlet nozzle pipe break was considered and the analysis assumed the full double-ended flow area. The break opening time for all postulated breaks was assumed to be one millisecond, which is consistent with Standard Review Plan, Section 3.6.2, "Determination of Break Locations and Dynamic Effects associated with the Postulated Rupture of

Piping." For the postulated reactor pressure vessel nozzle breaks, time varying loads transmitted to the reactor vessel support system would originate from three principal causes. These are:

(1) Reaction forces which would consist of blowdown jet forces and the release of strain energy resulting from the postulated rupture mechanism and the expulsion of fluid.

(2) Transient differential (asymmetric) pressures in the annular region between the outside of the vessel and the inside of the shield wall (reactor cavity pressurization).

(3) Transient differential (asymmetric) pressures across the core barrel within the reactor vessel.

The structural analyses were performed by applying the above loads simultaneously. These loads would be resisted by the following two mechanisms: (1) the four attached primary coolant loops with the steam generator and reactor coolant pump primary supports and; (2) four reactor vessel support pads and shoes beneath each alternate reactor vessel nozzle. The thermal hydraulics computer code "MULTIFLEX," which has been approved by the staff, was employed for the reactor vessel support system analysis.

The results of the analyses of the response due to asymmetric pressure loads and loss-of-coolant loop depressurization loads, when combined with the response due to safe shutdown earthquake and normal loads, have demonstrated that the structural integrity of the reactor pressure vessel, steam generator and reactor coolant pump support structures, reactor coolant loop piping, core support structures and other internals, as well as the functionability of control rods, would be maintained under these extreme loadings.

In addition, the steam generator upper lateral supports were also analyzed for the effects of asymmetric pressure load responses combined with the loss-of-coolant load response due to postulated breaks in the primary coolant loop and a postulated main steam line break. The maximum response due to a pipe break was then combined with seismic and normal loads.

The square-root-of-the-sum-of-the-squares method, which we find acceptable as discussed in NUREG-0484 "Methodology for Combining Dynamic Responses," was used to combine all loads resulting from asymmetric pressure, loss-of-coolant accident loop depressurization, a safe shutdown earthquake and normal loads for primary coolant system component and support structures. The results of this analysis demonstrated that the resulting stresses for all primary component support members are below the stress limits defined in the ASME Boiler and Pressure Vessel Code, Section III, Subsection NF, Article XVII-2000 and, therefore, are acceptable.

On the basis of our evaluation, we have concluded that the primary coolant system components and support structures under the effects of asymmetric pressure and loss-of-coolant accident loads are acceptable and that Salem Unit 2 can be safely operated. Therefore, we consider this matter resolved.

3.9.5 Piping System Support Base Plates

In Supplement No. 3 to the Safety Evaluation Report, we stated that we had requested information from the applicants as to how support plate flexibility had been considered in calculating maximum expansion anchor bolt loads. We further stated that upon receipt of this information, we would evaluate it and report the results in a supplement to the Safety Evaluation Report.

On March 8, 1979, our Office of Inspection and Enforcement issued IE Bulletin No. 79-02, "Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts," dated March 2, 1979. This bulletin was issued to all plants, both operating and under construction, including Salem Unit 2, and is concerned with many aspects of the design and installation of piping system supports, including the above mentioned issue of support plate flexibility.

On August 17, 1979, we met in Bethesda, Maryland, with representatives of Public Service Electric and Gas Company to discuss the Salem Unit 2 response to IE Bulletin No. 79-02. For purposes of responding to this bulletin, the Public Service Electric and Gas Company has joined an owners group which has contracted with Teledyne to perform certain generic testing of various expansion anchor bolts. During this meeting the applicants described how they were using the results of the generic Teledyne program for the specific expansion anchor bolts in use at Salem Unit 2. Additionally, the applicants described the status of the analyses and tests being performed on the expansion anchor bolts installed at Salem Unit 2.

Approximately 10,000 expansion anchor bolts are used in Salem Unit 2 of which approximately 7,000 are on safety related systems. Of these safety related expansion anchor bolts, 1,295 are associated with 362 baseplates, nearly all of which are floor mounted. The remaining safety related expansion anchor bolts are used to connect structural steel directly to walls and ceilings. All expansion anchor bolts used in Salem Unit 2 are of the wedge type, specifically, Hilti Quik-Bolts.

The applicants stated that the original expansion anchor bolt design criteria specified a minimum factor of safety of four against pullout and assumed baseplate rigidity. During its reevaluation of expansion anchor bolt adequacy, the applicants are using acceptable analytical tools developed by Teledyne to account for baseplate flexibility. In addition, the applicants are using an elliptical shear-tension interaction curve with a minimum factor of safety of four against manufacturer's specified ultimate bolt capacities, which is also acceptable. Therefore, the issue of the applicants' methods for considering support plate flexibility, as described in Supplement No. 3 to the Safety Evaluation Report, is acceptably resolved.

In responding to IE Bulletin No. 79-02, the applicants are proceeding with a program to verify the correct installation of both the floor mounted expansion anchor bolts and the wall and ceiling mounted expansion anchor bolts.

Certain installation practices used by the applicants have made the floor mounted expansion anchor bolts largely inaccessible for purposes of verifying correct installation. Therefore, for a sample of these floor mounted expansion anchor bolts, the applicants are performing hydraulic pull tests to demonstrate a factor of safety of four against pullout. The applicants anticipate approximately 150 of these pull tests will be necessary to demonstrate a 95/95 confidence level for each safety related piping system.

For 100 percent of the wall and ceiling mounted expansion anchor bolts, the applicants have completed a program which verified correct embedment depth. The applicants have also proposed, and are currently implementing, a test program to verify the setting of the wedges for a sample of the wall and ceiling mounted expansion anchor bolts. We have reviewed and approved the scope and procedures for this testing program. The applicants have committed to complete this testing program before Salem Unit 2 achieves criticality and that any required hardware changes will be completed within 60 days thereafter. We find this commitment to be acceptable. We note that the initial test results are positive and we anticipate few hardware changes to be necessary.

The applicants' program for responding to IE Bulletin No. 79-02 is proceeding in an acceptable manner and will be completed within a time frame which we have approved as discussed above. Our Office of Inspection and Enforcement will be monitoring the remaining portions of the applicants' program until their completion. All of the applicants' efforts to date demonstrate that essentially all of the existing expansion anchor bolts are adequate.

3.10 Seismic Qualification of Seismic Category I Instrumentation and Electrical Equipment

In Section 3.10 of Supplement No. 3 to the Safety Evaluation Report, we stated that the seismic Category I mechanical, instrumentation, and electrical equipment had been qualified by the applicants, and that some of this equipment was qualified by the applicants and that some of this equipment was qualified in accordance with the procedures of Institute of Electrical and Electronics Engineers Standard 344-1971, "Seismic Qualification of Class I Electric Equipment for Nuclear Power Generating Stations." We concluded that the issue of equipment seismic qualification would be resolved upon successful completion of a review of the qualification records together with a site examination of the equipment as installed.

Subsequently, our Seismic Qualification Review Team performed a review to determine whether the original equipment qualification for Salem Unit 2 performed in accordance with the procedures of Institute of Electrical and Electronics Engineers Standard 344-1971 could meet current licensing criteria as described in Standard Review Plan Section 3.10, "Seismic Qualification of Category I Instrumentation and Electrical Equipment." During this review we evaluated a representative sample of the Salem Unit 2 seismic Category I mechanical, instrumentation, and electrical equipment, with special emphasis on that equipment most critical to shutting the plant down following an earthquake. Prior to our Seismic Qualification Review Team review, the applicants demonstrated that the seismic qualification of many items meet current licensing criteria. As a result, our review at the Salem site on February 26-28, 1979, uncovered relatively few pieces of equipment for which it was not clear that the seismic qualification was completely in accordance with current licensing criteria. To clear up our reservations about these few items, the applicants submitted additional information and clarification. This follow-up information satisfied our questions, and equipment requalification was not required.

Therefore, we find that all seismic Category I mechanical, instrumentation, and electrical equipment have been qualified in a manner which exceeds the requirements of Institute of Electrical and Electronics Engineers Standard 344-1971, and we conclude that the applicants' original seismic qualification program, as augmented by the additional information obtained during our Seismic Qualification Review Team review, was sufficiently conservative to meet the requirements of the Standard Review Plan Section 3.10.

We, therefore, conclude that the Salem Unit 2 seismic Category I mechanical, instrumentation, and electrical equipment have been adequately qualified and are capable of performing their safety function during or after a safe shutdown earthquake. We consider this matter resolved.

3.11 <u>Environmental Design of Engineered Safety Features Equipment</u>

In Supplement No. 3 of the Safety Evaluation Report, we identified a number of outstanding issues regarding the environmental qualification of safety related Class 1E equipment for which additional information would be required. Subsequent to the issuance of Supplement No. 3, the applicants have submitted responses to our concerns. Our evaluation of these matters is as follows:

(1) With respect to a postulated main steam line break inside containment, as discussed in Section 6.2 of this report, the applicants have calculated the environmental conditions inside containment following such a postulated accident. We have performed a confirmatory analysis using the applicants input data and determined that a temperature profile which remains at 350 degrees Fahrenheit for one minute and above 300 degrees Fahrenheit for three minutes, is acceptable for equipment qualification.

(2) With respect to the Barton Pressure and Differential Pressure Transmitters, in September 1978, Westinghouse had provided test results for the environmental qualification of Barton Models 763 and 764 Lot 1 transmitters (Letter

Report NS-TMA-1950). Based on our review of these tests results, we concluded that the instruments would perform their short-term safety functions. However, we required that additional testing be conducted to confirm the capability of the transmitters for longer term post-accident monitoring. In September 1979, Westinghouse provided the results of these supplemental tests.

In the original tests, an attempt was made to demonstrate the qualification of these transmitters by subjecting them to high radiation levels corresponding to post loss-of-coolant accident conditions and, subsequently, exposing them to the high temperature steam conditions representative of main steam line break accidents. This combined test was performed to circumvent the need for separate tests for these accident conditions. This combination of high radiation and temperature, while not causing the transmitters to fail, resulted in excessive instrument error.

The supplemental tests which followed were based upon radiation levels and subsequent exposure to a steam environment corresponding to loss-of-coolant accident conditions and, in separate tests, to main steam line break accident conditions. Additional tests were also conducted to investigate the effects of radiation and temperature separately and in combination. This was done to promote an understanding of the phenomena which caused the errors and to provide a basis to support the conclusion that the transmitters are qualified to operate satisfactorily under the required service conditions. While the supplemental tests results support the conclusions that the Barton Lot 1 instruments will function in an accident environment, we do not believe that these instruments provide a sufficient margin of safety to justify their use throughout the life of the plant. Further improvements to obtain an additional margin of safety are warranted due to the safety significance of the information provided for post accident recovery by these instruments.

At Salem Unit 2, these transmitters are located in equipment enclosures which reduce the peak temperature to which they would be exposed in an accident. The applicants have submitted Revision A to Wyle Laboratory Report No. 44439-2 which presents the results of tests to demonstrate the protection provided by the enclosures. These results show that the transmitters would not be exposed to temperatures above 300 degrees Fahrenheit during the period where the external environment reaches 350 degrees Fahrenheit. However, after about 30 minutes the temperature within the enclosure comes up to within 10 degrees Fahrenheit of the temperature of the external environment. We conclude that these enclosures will provide an additional margin of protection in the short term in an accident. However, it does not alter our conclusion on the overall adequacy of the qualification of the Barton Lot 1 transmitters. Accordingly, we will permit the use of the Barton Lot 1 Transmitters until the second refueling outage. At that time, modified or replacement transmitters, that have been demonstrated to have a greater tolerance to harsh environments, will be required. Our Office of Inspection and Enforcement will verify that these modifications are implemented at that time.

(3) With regard to Rosemont transmitters, we had questioned the applicability of the qualification data for Rosemont Model 1153A transmitters as provided in Rosemont test report No. 3788. That report describes simulated design basis event tests in which the transmitters were subjected to a temperature rise to 350 degrees Fahrenheit over a period of 2-1/2 minutes. However, typical rise times for both loss-of-coolant and main steam line break accidents are about 10 to 20 seconds.

In a letter dated March 6, 1979, the applicants referenced additional test data on the Rosemont transmitters provided by the Arkansas Power and Light Company for the Arkansas Nuclear One - Unit 2 application (Docket No. 50-368). This data demonstrated the capability of the Rosemont transmitters to function properly when exposed to a temperature increase to 270 degrees Fahrenheit in 12.5 seconds.

In addition, the applicants stated that the Rosemont transmitters are located in equipment enclosures. Thus the environmental effects of design basis events would be reduced. The test results obtained at Wyle Laboratory, as discussed in item (2) above, demonstrate that a lower temperature and a lower rate of temperature rise occurs within the enclosure in response to a postulated design basis event. As a result, we conclude that the protection provided by the equipment enclosures and the Rosemont test results provide an adequate basis to demonstrate the qualification of these transmitters. Therefore, we consider this matter resolved.

With respect to Conax seals, the equipment enclosure tests included a Rosemont transmitter in the enclosure to qualify the electrical interface for this instrument. The qualification tests demonstrate that the Conax seals did not leak steam or moisture. Therefore, we consider this matter resolved.

(4) With regard to solenoid valves, the applicants have submitted Automatic Switch Company test report No. AQS 21678/TR to demonstrate the adequacy of Automatic Switch Company solenoid valves for design basis events. The tests were conducted for a generic loss-of-coolant accident environment which has a maximum temperature of 346 degrees Fahrenheit. The temperature for these tests was increased from an initial temperature of 140 degrees Fahrenheit to 280 degrees Fahrenheit in one minute and subsequently was raised to a value of 346 degrees Fahrenheit which was held for an additional four minutes. The enclosure tests discussed in item (2) above demonstrate that those solenoid valves located in equipment enclosures will be subjected to a lower temperature. We conclude that the results of the Automatic Switch Company tests and the results of the Wyle tests on enclosures are adequate to demonstrate that the solenoid valves mounted in equipment enclosures are qualified.

The applicants have submitted Wyle test report No. 44439-1 to demonstrate the adequacy of Automatic Switch Company solenoid valves which are not mounted in equipment enclosures. These tests were conducted using the same solenoid valves which had undergone tests documented in the referenced Automatic Switch Company test report.

These tests did not specifically address the operability of these valves under post accident conditions where it may be desirable to reopen valves which were closed to obtain the desired protective action. This would require that the solenoids be energized at a time when the environment temperature is above normal. However, since these valves were subjected to multiple cycles of the simulated design basis event and the tests demonstrated that the valves were operable at the end of each test cycle, we conclude that sufficient margin exists to assure their operability.

The results of these tests demonstrate the adequacy of the environmental qualification for Automatic Switch Company solenoid valves located in containment. Therefore, we consider this matter resolved.

(5) With respect to limit switches, the applicants have submitted Acme-Cleveland Development Company qualification test report of NAMCO Model EA-180 limit switches. During the qualification tests, the temperature was initially increased from 140 degrees Fahrenheit in ten seconds with a subsequent increase to 340 degrees Fahrenheit which was held for three hours. The temperature was reduced to 140 degrees Fahrenheit over the next two hours with a subsequent increase to 340 degrees Fahrenheit in ten seconds which was held an additional three hours. While the peak temperature reached during the test was slightly below the maximum value of 350 degrees Fahrenheit calculated for a main steam line break accident, as discussed in item (1) above, the three hour hold at 340 degrees Fahrenheit provides assurance that the limit switches are adequate for Salem Unit 2 design basis events.

The applicants have indicated that the electrical connection interface will be sealed with a potting compound such as Scotchcast No. 9 resin. This sealant was qualified by Wyle Laboratories and the test results are reported in Wyle test report No. 44107-1. In order to improve maintainability, the applicants intend to replace these seals with Conax Electric Conduction Seal Assemblies during the first refueling outage. This replacement seal has also been qualified as documented in Conax Report No. ITS-409. Therefore, we consider this matter resolved.

The applicants had intended to use the NAMCO limit switch as a replacement for stem mounted limit switches used to provide position indication on air and motor operation isolation valves. Replacement was required because the original switches were found to be unqualified. However, the applicants found that the replacement switch could not be installed on six of the valves because of size limitations.

All six valves serve to isolate small sampling lines. The limit switches were a part of the valve control circuits such that a switch failure could result in inadvertant opening of the valve following a reset of the automatic closure initiated by the protection system. Rather than replace the existing switches with the qualified equipment, the applicants have modified the control circuits for these six valves to remove the limit switch from the control circuit and thus prevent a limit switch failure which could result in an undesired action. Since the protective action is obtained by the automatic closure of one valve on each side of the containment barrier, the requirement of the single failure criterion is met independent of any potential failure of position indication. We conclude that this provides a suitable basis for not using qualified limit switches for these specific cases as identified by the applicants.

(6) With regard to instrument panels and enclosures, as discussed in item (2) above, Wyle test report No. 44439-2 was submitted covering the environmental qualification of equipment located inside enclosures. We find that the test results and analysis provided in this report provide an adequate basis to demonstrate a reduction in the environmental conditions used for the justification of qualification of components located therein. We consider this matter resolved.

(7) With respect to test procedures, the applicants have provided additional information on qualification reports that describe the test procedures and test results for each piece of equipment listed in Table Q7.18-1 of the Final Safety Analysis Report. On-site review of these qualification methods and procedures for seismic Category I mechanical components, electrical instrumentation and control equipment, and their supporting structures was made by the NRC Seismic Qualification Review Team on February 26-28, 1979. The applicants have provided a response to our concerns raised during the site visit. Based upon our review of the information provided by the applicants and our observations during the site visit, we find that adequate documentation has been provided to verify the seismic qualification of safety related equipment. We consider this matter resolved.

(8) With regard to Class 1E equipment located outside of the containment structures, the applicants indicated in a letter dated March 8, 1979, that these areas are provided with environmental control systems to maintain temperatures within a specified range. These systems have been designed with sufficient redundancy in controls and actuated equipment to assure that the environmental temperature limits of the equipment will not be exceeded during any mode of operation including plant shutdown. All areas, except for the switchgear rooms, served by these systems are provided with temperature monitoring and/or control devices which activate alarms in the control room in the event that temperature limits are exceeded. The status of ventilation equipment operability is also monitored in the control room. A record of the temperature in these areas will provide data for subsequent analysis of

equipment capability in the event that temperatures exceed normal limits. The record of temperature in these areas is provided by using trend recording capabilities of the plant computer.

On the basis of our review, we conclude that the applicants' temperature control and monitoring system for Class 1E equipment areas provides reasonable assurance that the environment will be maintained within the temperature range for which the equipment is qualified to operate. The applicants will provide a temperature sensor in the switchgear rooms. Our office of Inspection and Enforcement will verify that this sensor is installed prior to issuance of an operating license. Therefore, we consider this matter resolved.

We have reviewed Westinghouse Topical Report WCAP-9157, "Environmental Qualification of Safety Related Class 1E Process Instrumentation," which contains the environmental qualification results for the main coolant loop resistance temperature detectors. These temperature sensors provide data to confirm natural circulation cooling as well as data to ensure an adequate margin of subcooling to prevent steam formation in the reactor coolant system. We questioned the basis for the assessment that the normal and post accident radiation exposure would be limited to a radiation dose for which the resistance temperature detectors were qualified. The applicants provided a response to our concern which concluded that the resistance temperature detectors used for post accident monitoring are adequate if replaced after 14 years of operation. We conclude that this evaluation did not include assumptions which contained an adequate degree of conservatism. Therefore, we will condition the operating license to require the replacement of resistance temperature detectors used for post accident monitoring at each refueling outage pending requalification of the sensors to a higher radiation dose which is based on a conservative assessment of post accident radiation levels plus the normal radiation dose for their service life. Our Office of Inspection and Enforcement will verify that such replacements are accomplished at each refueling.

In June of 1979, Westinghouse reported a potential safety hazard under 10 CFR Part 21. This report addressed errors caused in steam generator level indication following high energy pipe breaks inside containment. High ambient temperatures due to accidents can result in a decrease in the water column density for the level instrument reference leg with a consequent increase in the indicated steam generator water level (i.e., indicated water level exceeding actual level). As a result, we requested that the applicants evaluate the effects of such errors for all level measurement systems in containment. This review led to a decision to insulate the reference legs for steam generator level measurements. An assessment of errors was made in order to establish the low-low steam generator level trip setpoint. This evaluation included normal system errors in addition to the errors which can occur due to a high temperature environment for both the level reference leg and level transmitter. The low-low steam generator level trip will be set at 17 percent and includes a three percent margin of safety in addition to accumulated errors. We have reviewed the applicants' evaluation of level measurement errors, for their impact on post accident operation, to assure that adequate water level will be maintained in the pressurizer and steam generator. We conclude that acceptable means have been established to address potential errors in the level measurement systems for trip setpoints and for operation under post accident conditions.

We have recently published guidance to be used in environmentally qualifying electrical equipment (see NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment"). Recognizing that the equipment qualification review for the Salem Unit 2 has been a long-term effort spanning several years, we recently required that the applicants reassess their qualification documentation for equipment installed at Salem Unit 2 with the purpose of establishing that the qualification methods used and results obtained are in conformance with the staff guidance contained in NUREG-0588. We believe that this additional review will confirm our earlier conclusions regarding the adequacy of the qualification documentation and, therefore, that it need not be completed prior to licensing Salem Unit 2 for low power operation. We will require that, prior to full power operation, the applicants confirm the adequacy of qualification for all safety-related electrical equipment that could be exposed to a harsh environment.

4.0 REACTOR

4.2 Mechanical Design

4.2.1 Fuel

In Section 4.2.1 of Supplement No. 3 to the Safety Evaluation Report, we concluded that subject to (1) documentation of a comparison with criteria used for the North Anna Power Station, Units 1 and 2 fuel design (Docket Nos. 50-338 and 50-339) and (2) completion and issuance of our safety evaluation of Westinghouse Topical Report WCAP-8288, "Safety Analyses of the 17 x 17 Fuel Assembly for Combined Seismic and Loss of Coolant Accident," the seismic and loss-of-coolant forces on the fuel assembly for Salem Unit 2 had been properly analyzed.

A comparison between the criteria used for the North Anna fuel design and the Salem Unit 2 fuel design was presented in a letter from T. M. Anderson of Westinghouse to O. Parr of NRC, dated January 12, 1979. We reviewed the information provided by the applicants and have determined that the criteria used in the Salem fuel design compared favorably with the criteria used in the North Anna fuel design which was previously approved by us. Our safety evaluation of WCAP-8288 has been issued and is presented in a letter from J. F. Stolz of NRC to T. M. Anderson of Westinghouse, dated February 6, 1979. In our safety evaluation of WCAP-8288, we concluded that the methods for analyzing the mechanical response of fuel assemblies to seismic and loss-of-coolant accident loads are acceptable.

We have reviewed the documentation presented by the applicants and have confirmed that the grid strength margin is adequate. For the loss-of-coolant accident analysis, the applicants selected an inlet nozzle break inside the biological shield using a conservative break time of one millisecond and a realistic average break opening area of 55 square inches. When the loss-of-coolant accident load is combined with the safe shutdown earthquake load by the square-root-of-the-sum-of-the-squares method, the resulting grid load is substantially lower than the experimentally measured grid strength. A safety factor of approximately 1.9 is demonstrated by this analysis whereas a safety factor of 1.75 has been previously found acceptable (e.g., for the North Anna Power Station fuel assembly). Therefore, we conclude that the Salem Unit 2 fuel assembly seismic and loss-of-coolant accident analysis is acceptable.

4.2.2 Fuel Design

As stated in Section 4.2 of the Safety Evaluation Report, the fuel for Salem Unit 2 is the Westinghouse 17 x 17 design. This fuel design is currently operating in six plants, including Salem Unit 1. Three such plants have completed the first cycle of operation, and fuel inspections have been performed.

Subsequent to the issuance of the Safety Evaluation Report, Westinghouse has substantially changed its methods of fuel performance analysis. In addition, after the issuance of Supplement No. 3 to the Safety Evaluation Report, an unexpected number of failures in two assembly components (grid straps and control spiders) was observed during refueling at Salem Unit 1. Furthermore, guide tube wear has been observed at several operating pressurized water reactors. These analytical changes, component failures and guide tube wear, and their impact on Salem Unit 2 are discussed and evaluated below.

Thermal Performance Analysis

The new Westinghouse fuel thermal performance code (PAD 3.3) is described in WCAP-8720, "Improved Analytical Methods Used in Westinghouse Fuel Rod Design Calculations," October 1976. This code contains a revision of an earlier fission gas release model and revised models for helium solubility, fuel swelling, and fuel densification.

The new Westinghouse code was approved with four restrictions as described in our safety evaluation of February 9, 1979 (letter from J. Stolz, NRC to T. Anderson, Westinghouse). Three of those restrictions deal with numerical limits and have been complied with. The fourth restriction relates to use of the PAD-3.3 code for the analysis of fission gas release from uranium dioxide (UO_2) for power increasing conditions during normal operation. This restriction applies to the safety analysis of Salem Unit 2. However, Westinghouse has stated that this restriction does not adversely affect the results of the safety analyses performed for Salem Unit 2. Although we believe that this is essentially correct for the planned operation of Salem Unit 2, Westinghouse has prepared and submitted a detailed evaluation of this restriction. In our previous evaluation, we agreed that the PAD-3.3 code may be used for the analysis of constant high power level conditions which conservatively bound power increasing conditions during normal operation.

For operation at five percent of full power, the restriction for PAD-3.3 is not significant and the analysis as presently docketed is acceptable. We will complete our review of the Westinghouse evaluation (and the applications of the revised model) prior to authorizing operation at full power.

Grid Straps

During a recent refueling at Salem Unit 1, strap damage on a number of spacer grids was observed on discharged assemblies. Similar damage had been reported previously (WCAP-8183, Revisions 1 through 8, "Operational Experience with Westinghouse Cases") but never to the extent observed at Salem Unit 1, where 31 fuel assemblies suffered some damage. The damage ranged from deformed edges and small chips to loss of full strap width pieces, and was usually confined to one or two of the eight grids per assembly. An evaluation for Salem Unit 1 showed that such grid strap damage was not detrimental to the operation of the reactor (see Amendment No. 20, October 1979, to the Salem Unit 1 operating license DPR-70, Docket No. 50-272). This evaluation considered thermal-hydraulics, neutronics, grid-cell deformation, flow blockage from loose pieces, and control rod interference. The effects of all of these were found to be insignificant. We have reviewed the evaluation performed on Salem Unit 1 and have determined that it is also applicable to Salem Unit 2. Therefore, we conclude that if such grid strap damage were to occur on Salem Unit 2, it would not be detrimental to the operation of the reactor.

Westinghouse has recommended certain procedural changes that are designed to minimize or eliminate such damage during fuel handling. These recommendations are based on the following: (1) loading sequence as to the buildup of rows and corner positions in the core, (2) offset into the open regions for vertical movement of assemblies, and (3) revised load cell limits on the refueling crane to increase the sensitivity in detecting spacer grid interference. In a letter, dated August 28, 1979, the applicants have agreed to follow these recommendations at Salem Units 1 and 2. The division of Operating Reactors Information Memorandum No. 19 issued on October 25, 1979, also requests all licensees of 17 x 17 plants to visually inspect their discharge fuel for grid strap damage. Should these inspections reveal significant strap damage, further changes to the fuel handling procedures will be made. On the basis that grid strap damage is not detrimental to reactor operations and that steps will be taken to minimize its occurrence, we find that this matter is satisfactorily resolved.

Control Spiders

Another core component failure, involving control rod spiders, was also observed at Salem Unit 1. Eight alignment fingers on six spiders failed during plant operation. Thus, eight control rodlets became detached and were inserted into the core producing an observed flux tilt. This failure was traced to a manufacturing procedure that introduced a contaminant that led to stress-corrosion cracking of the finger. This manufacturing procedure was primarily used for two lots of fingers, and the procedure has since been corrected to eliminate the problem. A complete evaluation of this problem and its safety implications is contained in Amendment 20 to the Salem Unit 1 operating license DPR-70.

That evaluation agrees with the Westinghouse conclusions which are as follows:

(a) Failures do not represent a structural inadequacy or generic design weakness.

(b) Failures are the result of stress corrosion cracking and were contained within the two receiving lots of other fingers.

(c) Elimination of all rod control clusters containing fingers from the suspect lots should prevent recurrence.

The evaluation goes on to show that even if rodlets were dropped, the safety effects for the core would depend upon the number of dropped rodlets. A few dropped rodlets (about 10) could cause a flux tilt but the core parameters could be maintained within the Technical Specification limits. A larger number of dropped rodlets (about 50) would be needed to cancel the excess shutdown margin or significantly affect peaking factors, but such a quantity would be easily detected and appropriate actions taken. In light of the low probability of the future occurrence of dropped rodlets and the fact that the dropping of significant number of rodlets would be detected, this matter was adequately resolved for Salem Unit 1. We have reviewed the evaluation performed on Salem Unit 1 and have determined that it is also applicable to Salem Unit 2. Therefore, we consider this acceptably resolved for Salem Unit 2.

Guide Tube Wear

An unexpected degradation of guide thimble tube walls has been observed during post-irradiation examinations of irradiated fuel assemblies taken from several operating pressurized water reactors. Subsequently, it has been determined that coolant flow up through the guide thimble tubes and turbulent cross flow above the fuel assemblies have been responsible for inducing vibratory motion in the normally fully withdrawn ("parked") control rods. When these vibrating rods are in contact with the inner surface of the thimble wall, a fretting wear of the thimble wall occurs. Significant wear has been found to be confined to the relatively soft Zircaloy-4 thimble tubes because the control rod claddings -- stainless steel for Westinghouse reactor designs -- provide a relatively hard wear surface. The extent of the observed wear is both time and reactor design dependent and, in some non-Westinghouse reactors, has been observed to extend completely through the guide thimble tube walls, thus resulting in the formation of holes.

Guide thimble tubes function principally as the main structural members of the fuel assembly and as channels to guide and decelerate control rod motion. Significant loss of mechanical integrity due to wear or hole formation could (1) result in the inability of the guide thimble tubes to withstand their anticipated loadings for fuel handling accidents and transients and (2) hinder scramability.

In response to our attempt to assess the susceptibility and impact of guide thimble tube wear in Westinghouse plants, Westinghouse has submitted information on its experience and understanding of the issue, by letters dated September 12, 1978, December 15, 1978 and June 27, 1979. This informatin consisted of guide thimble tube wear measurements taken on irradiated fuel assemblies from Point Beach, Units 1 and 2 (Docket Nos. 50-266 and 50-301), two-loop plants using 14x14 fuel assemblies. Also described was a mechanistic wear model (developed from the Point Beach data) and the impact of the model's wear predictions on the safety analyses of plant designs such as those utilizing 17x17 fuel assemblies.

Westinghouse believes that its fuel designs will experience less wear than that reported in other reactor designs because the Westinghouse designs use thinner, more flexible, control rods that have relatively more lateral support in the guide tube assembly of the upper core structure. Such construction provides the housing and guide path for the rod cluster control assemblies above the core and thus restricts control rod vibration due to lateral exit flow. Also, Westinghouse believes that its wear model conservatively predicts guide thimble tube wear and that, even with the worst anticipated wear conditions (both in the degree of wear and the location of wear), its guide thimble tubes will be able to fulfill their design functions.

We have reviewed this information and conclude that the Westinghouse analysis accounts for all of the major variables that control this wear process. However, because of the complexities and uncertainties in determining (1) contact forces, (2) surface-to-surface wear rates, (3) forcing functions and (4) extrapolations of these variables to other fuel designs (such as the 17x17 design used in Salem), we believe that it is prudent for the applicants to participate in a surveillance plan for the examination of guide thimble wear.

The specifics of such a surveillance program have not yet been determined, but since the wear phenomenon is a time-dependent process, the details of such an inspection program do not need to be specified prior to the first refueling outage for Salem Unit 2. Furthermore, such inspections may not have to be conducted at Salem. For example, the applicants could join in a cooperative owners group and thereby submit applicable information derived from a similar type of plant using 17x17 fuel assemblies. For acceptability, the minimum objective of such a program should be to demonstrate that there is no occurrence of hole formation in rodded guide thimble tubes.

In their letter of February 14, 1980, the applicants agreed to provide results from a surveillance program as described above. Therefore, this issue is acceptably resolved for the first cycle of operation. This issue should be resolved for later cycles of operation when those surveillance results confirm the predictions of the analysis described above. If the surveillance results do not confirm the predictions of the analysis, we will require that the applicants take appropriate action to account for increased wear.

4.3 Nuclear Design

Subsequent to the issuance of Supplement No. 3 to the Safety Evaluation Report, Westinghouse submitted a 10 CFR Part 21 notification, in a letter dated April 23, 1979, regarding a non-conservatism in the single rod drop event. In three loop Westinghouse power plants, the reactor control system obtains its power signal from a dedicated excore detector. Recent spatial analyses by Westinghouse indicate that for a dropped rod in the core quadrant adjacent to the dedicated excore detector, the power overshoot when the reactor is in the automatic mode is greater than the value calculated by the methods used in the Safety Analysis Report. This could lead to exceeding the departure from nucleate boiling limit. No credit is taken in the analysis for the negative flux rate trip. Westinghouse proposed an adjustment of the negative flux rate trip constants for all its reactors without turbine runback to trip the reactor on any single dropped rod. This would then preclude a departure from nucleate boiling problem as a result of a dropped rod.

The adjustment of the negative flux rate trip constants was proposed for all Westinghouse reactors without turbine runback, even though Westinghouse believes their analyses for two and four loop reactors will continue to show that there is not a departure from nucleate boiling problem. However, the recommendation to adjust the negative rate flux trip was made to ensure additional conservatism until Westinghouse can provide and we can review a topical report showing details of the analysis for all types of Westinghouse power plants.

In order to ensure that the drop of any rod will cause a reactor trip regardless of rod worth and location, the applicants have submitted proposed Technical Specifications lowering the rate-lag circuit time constant from two seconds to one second, and lowering the nominal negative flux rate trip value from negative five percent to a negative three percent. The limiting safety system setpoint remains equal to or greater than one second for the time constant, but is equal to or less than negative 3.5 percent for the negative flux rate trip value. These new setpoints result in reactor trips for negative flux rates which are one percent to two percent per second slower than would have occurred with the original setpoints. The new setpoints are designed to ensure that a reactor trip will occur for any dropped rod. Therefore, the potential for the automatic control system causing power overshoots as a result of a dropped rod would be eliminated.

The rate-lag circuit output is a direct function of the time constant and is used in the high positive flux rate trip circuit (whose trip setpoint is not being changed). The net result in lowering the time constant from two seconds to one second is that some positive flux ramps which previously would have caused reactor trips will not do so now. However, these positive flux ramps (permitted by the new setpoints) are relatively low rates and are generally in the range of those produced by the automatic control system (i.e., not rod ejections). The Final Safety Analysis Report states that protection for rod ejection accidents is provided by the high flux (high and low setpoints) signal, and the high positive rate trip function is a "complementary" trip. Changing the rate-lag circuit time constant will not alter this role of the high positive flux rate trip.

As part of its continuing analysis of single rod drops, Westinghouse has found several new nonconservatisms which indicate that the trip setpoint changes made earlier do not necessarily provide the desired protection. This was discussed at a meeting with Westinghouse on November 19, 1979 in Bethesda, Maryland. At the meeting, Westinghouse suggested an interim procedural position which would provide protection in single rod drops. This position, which the staff approved, was offered until a long term solution to the problem can be developed, and is as follows:

(1) The plant may operate in manual control from zero percent to 100 percent power with no changes in the current rod insertion limits.

(2) The plant may operate in automatic control from zero percent to 90 percent power with no changes in the current rod insertion limits; above 90 percent power the D control rod bank would have to be withdrawn to 215 steps or greater.

In a letter, dated February 26, 1980, the applicants have agreed to implement these restrictions on Salem Unit 2.

The basis for our finding the interim position acceptable is that it prevents an overshoot above full rated thermal power in the event of a dropped rod. For power levels equal to or greater than 90 percent in automatic control, a dropped rod event will result in a withdrawal demand from the rod control system. Since differential rod worth of the D bank while above 215 steps is negligible, the reactivity required for a power overshoot is not available. For rod drops below 90 percent power in automatic control, an analysis by Westinghouse shows that the reactor will not overshoot above rated power. In manual control, the operator will not react to cause a power overshoot. Thus, the departure from nucleate boiling design limit is not exceeded and, consequently, we find the interim position acceptable.

5.0 REACTOR COOLANT SYSTEM

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.1 Fracture Toughness

5.2.1.1 Compliance with Code Requirements

In Section 5.2.1.1 of Supplement No. 3 to the Safety Evaluation Report, we stated that the applicants would request an exemption to 10 CFR Part 50, Appendix G as it relates to the vessel bolting material requirements.

In a letter dated February 12, 1979, the applicants stated that the requirements of Appendix G to 10 CFR Part 50 were met for Salem Unit 2, except for the specific requirement of Paragraph IV.A.4 of Appendix G. Paragraph IV.A.4 of Appendix G requires that a Charpy V-notch test program be conducted for the primary coolant pressure boundary ferritic bolting exceeding one inch in diameter to demonstrate that the bolting material (SA 540 B23) has a minimum toughness of 25 mils lateral expansion and a 45 foot-pounds impact energy at the lower of either the preload temperature or the lowest service temperature. As a result, alternate methods for compliance with the specific requirement of Paragraph IV.A.4 of Appendix G were proposed by the applicants and an exemption was requested from the identified requirement.

Subsequently, Paragraph IV.A.4 of Appendix G to 10 CFR Part 50 was revised (44 Fed. Reg. 55328, Sept. 28, 1979) such that this specific exemption is no longer necessary. We, therefore, find that Salem Unit 2 is now in full compliance with all of the requirements of Appendix G. We consider this matter to be resolved.

5.2.5 Steam Generator Tube Integrity

In Section 5.2.5 of Supplement No. 1 to the Safety Evaluation Report, we presented our evaluation of the applicants' measures for assuring steam generator tube integrity in Salem Unit 2. Our evaluation included the provisions for detecting degradation of tube wall integrity, should it occur. We concluded that those measures were acceptable.

Subsequent to the issuance of Supplement No. 3 to the Safety Evaluation Report, we required additional measures, relating to secondary water chemistry, steam generator inspection ports and plugging of certain tubes, to further assure the integrity of the steam generator tubes. Our evaluation of these measures is presented further below.

It should be noted that the steam generators for Salem Unit 2 are of a design having carbon steel supporting plates with drilled flow holes. Steam generators of this design in operating plants have experienced denting and cracking. Although an effective secondary water chemistry control program can reduce the rate of tube degradation, there is no assurance that a 40 year steam generator lifetime can be obtained.

Although the possibiilty of tube cracking exists, we have concluded that, with the additional measures mentioned above and discussed further below, operation of the steam generators will not constitute an undue risk to the health and safety of the public for the following reasons:

(1) Primary to secondary leakage rate limits, and associated surveillance requirements will be established to provide assurance that the occurrence of tube cracking during operation will be detected and appropriate corrective action, such as tube plugging, will be taken such that any individual crack present will not become unstable under normal operating, transient or accident conditions.

(2) Augmented inservice inspection requirments and preventative tube plugging criteria will be established to provide assurance that the great majority of degraded tubes will be identified and removed from service before leakage develops.

Secondary Water Chemistry

In a letter dated July 31, 1979, we requested the applicants to implement a secondary water chemistry monitoring and control program that included the following:

(1) Identification of a sampling schedule for the critical parameters and of control points for these parameters;

(2) Identification of the procedures used to measure the value of the critical parameters;

(3) Identification of process sampling points;

(4) Procedure for the recording and management of data;

(5) Procedures defining corrective actions for off-control point chemistry conditions; and

(6) A procedure identifying (a) the authority responsible for the interpretation of the data and (b) the sequence and timing of administrative events required to initiate corrective action.

In a letter, dated December 6, 1979, the applicants stated that all volatile chemical treatment of secondary water systems for control of dissolved oxygen and corrosion of ferritic metals and copper alloys will be used. Chemical treatment along with operation of condensate polishing and steam generator blowdown systems and a maintenance program will be used to control the source of secondary contamination (raw water inleakage across the condenser tubes, and air inleakage into the system). A sampling and analyses program in conjunction with inline monitors will provide the means of detecting and correcting out-of-limit chemistry conditions. Procedures will be instituted to provide instructions for the prompt notification of responsible plant personnel of out-of-limit secondary system chemistry and the steps to be taken to correct the situation. Records will be kept and maintained pertaining to secondary water chemistry to be used for evaluating past conditions in relation to possible subsequent operations.

In a subsequent letter, dated March 14, 1980, the applicants stated that they will also monitor the steam condensate at the effluent of the condensate pump for the purpose of detecting condenser leakage. When a condenser leak is confirmed, the leak will be repaired or plugged within 96 hours, in conformance with Branch Technical Position MTEB 5-3, "Monitoring of Secondary Side Water Chemistry in PWR Steam Generators."

We have reviewed the applicants' submittals, as discussed above, and find the provisions for the secondary water chemistry monitoring and control program to be acceptable.

<u>Inspection Ports</u>

For some forms of steam generator degradation which have occurred, eddy current testing and tube gauging alone are not sufficient to assess and monitor tube and support plate degradation. In order to perform adequate assessment and monitoring of these areas, we require that inspection ports be installed. These ports should be installed just above the upper support plate and between the tubesheet and the lower support plate and in line with the tube lane.

Under the as low as is reasonably achievable concept, we are requesting that all possible steam generator modifications be made prior to the start of operations in order to minimize personnel exposure. Based on experience obtained at the Surry Unit 1 facility (Docket No. 50-280), we have determined that these inspections ports can be installed in the four steam generators after start of operations at a personnel exposure of 10 man-rem. On this basis, we have determined that the level of exposure is not significant enough to justify the delay of the start-up of the plant to permit the installation of the inspection ports.

However, since secondary side contamination will increase as the operating time increases, we will require that these ports be installed prior to start-up after the first refueling.

Row 1 Steam Generator Tubes

Experience has shown that the small bend radius of the Row 1 tubes in the steam generators of Westinghouse manufacture leads to early onset of cracking. In order to forestall the need for early shutdowns due to leaking tubes, we require that the Row 1 tubes in the Salem Unit 2 steam generators be plugged prior to exceeding five percent power since these tubes are the ones most susceptible to the development of cracks.

5.2.6 Steam Generator Head Cladding

Subsequent to the issuance of Supplement No. 3 to the Safety Evaluation Report, the applicants have provided information, by letter dated March 30, 1979, concerning the discovery of metallurgical indications in the stainless steel cladding of the Salem Unit 2 steam generators. In this letter, the applicants concluded that, based on the metallurgical information obtained for the Unit 2 steam generators, surveillance of the Unit 2 steam generators was not required and that the most meaningful information could be derived from a continued ultrasonic inspection of the No. 14 steam generator cold leg in Unit 1.

In a letter, dated April 23, 1979, we advised the applicants that we had evaluated their proposal and found it unacceptable because the crack indications of the Salem Unit 2 steam generator channel heads have increased in severity and extent during pre-operational testing. We further stated that we require that the applicants demonstrate the integrity of the Unit 2 channelheads by monitoring the cracks in Unit 2.

In a letter, dated July 19, 1979, the applicants stated that they will monitor a selected area of the No. 21 steam generator channelhead in Unit 2 by ultrasonic examination. The area selected is in the lower portion of the cold leg (outlet) side of the No. 21 steam generator. This selection was made on the basis of a prominent interbead liquid penetrant indication between the outlet nozzle and the access manway.

The applicants have developed an inspection program such that a base line examination can be performed prior to startup of Salem Unit 2. In addition, the applicants have proposed a technical specification regarding an augmented inservice inspection program for the steam generator channelheads. The technical specification requires that the No. 21 steam generator channelhead shall be ultrasonically inspected in a selected area during each of the first three refueling outages using the same ultrasonic inspection procedures and equipment used to generate the base line data. These inservice ultrasonic inspections shall verify that the cracks observed in the stainless steel cladding prior to operation have not propagated into the base material.

We have reviewed the information submitted by the applicants related to steam generator cladding cracking and have determined that the additional inspection required by the technical specification will serve to verify that the clad crack does not propagate into the base material and is, therefore, acceptable.

5.3 Inservice Inspection Program

5.3.1 Inservice Testing of Pumps and Valves

In Supplement No. 3 to the Safety Evaluation Report we concluded that, subject to confirmatory documentation, the Salem Unit 2 inservice testing of Class 1, 2, and 3 pumps and valves is acceptable.

By letter dated January 4, 1979, the applicants submitted a description of their proposed inservice testing program for pumps and valves. The program includes both base line preservice testing and periodic inservice testing. It provides for both functional testing of components in the operating state and for visual inspection for leaks and other signs of degradation.

The date of the applicants' construction permit (September 25, 1968) places this plant under 10 CFR 50.55a(g)(1), which permits compliance to the extent practical with later editions and addenda of Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code. Since inservice testing requirements for pumps and valves were not included in the Code until the Summer 1973 addenda, well after the design of the plant was mostly complete, the applicants cannot in all cases meet the requirements of the 1974 Edition through the Summer 1975 Addenda of Section XI, which they have optionally selected to meet, and have requested relief from certain Code requirements as discussed below.

The applicants propose that the period for which the program is applicable be as follows:

(1) From the issuance of the operating license to the start of facility commercial operation, the preservice and inservice testing of American Society of Mechanical Engineers Code Class 1, 2, and 3 pumps and valves will be performed in accordance with Section XI, 1974 Edition through Summer 1975 Addenda;

(2) Following the start of facility commercial operation, inservice testing of pumps and valves will then be performed in accordance with the American Society of Mechanical Engineers Section XI Code and applicable addenda as required by 10 CFR 50, Section 50.55a(g)(4).

We have not completed our detailed review of the applicants' submittal. However, based on our preliminary review, we find that it is impractical within the limitations of design, geometry, and accessibility for the applicants to meet certain of the American Society of Mechanical Engineers Code requirements. Imposition of those requirements would, in our view, result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. Therefore, pursuant to 10 CFR 50.55a(g)(1), the relief that the applicants have requested from pump and valve testing requirements of the American Society of Mechanical Engineers Code is granted for that portion of the initial 120 month period during which we complete our review. Since the applicants will comply with Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code and/or the Technical Specifications, we find the Salem Unit 2 inservice testing program for pumps and valves to be acceptable.

6.0 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Containment Functional Design

In Supplement No. 3 to the Safety Evaluation Report, we stated that upon receipt of information related to subcompartment analysis, we would review the information and report our findings in a supplement to the Safety Evaluation Report. We also stated that we had not completed our review of the information provided by the applicants related to the main steam line break analysis. Our evaluation of these two matters is discussed below.

Subcompartment Analysis

In letters dated January 18, 1979 and March 6, 1979, the applicants provided an analysis of the pressure response of subcompartments inside the containment due to postulated high energy line breaks occurring in the reactor cavity and in the steam generator and pressurizer compartments. The applicants used the Westinghouse TMD code, with the non-augmented critical flow correlation and the compressibility factor "Y," for the analysis. We have previously reviewed the TMD code as part of our evaluation of Topical Report WCAP-8077, "Ice Condenser Containment Pressure Transient Analysis Methods," and have concluded that the TMD code is an acceptable code for the evaluation of subcompartment transient response. Our evaluation of WCAP-8077 was presented in a letter to Westinghouse Electric Corporation, dated December 18, 1973.

The blowdown rates from postulated primary system ruptures within containment subcompartments were calculated using the SATAN-V code. This code uses the modified Zaloudek correlation to calculate flow from the break when the fluid is subcooled and the Moody slip flow model is used when the bulk fluid is saturated. Stagnation conditions at the break are approximated by removing the momentum flux option from the SATAN-V code. This method is also documented in Topical Report WCAP-8312A, "Westinghouse Mass and Energy Release Data for Containment Design," which was approved by the NRC by letter, dated March 12, 1975.

The applicants have performed nodalization sensitivity studies for analyses of the reactor cavity and steam generator compartments. These studies showed that the nodal volume averaged pressure changed insignificantly as the nodalization schemes were varied. We, therefore, conclude that the nodalization of the compartments is acceptable.

The applicants have analyzed a spectrum of pipe breaks in the various subcompartments, with the limiting break being a postulated double-ended pipe rupture in each subcompartment. The design basis pipe break for the reactor cavity and steam generator subcompartments was a 100 square inch double-ended rupture, and for the pressurizer compartment was a double-ended surge line break. For all pipe breaks analyzed, the peak calculated differential pressure across a subcompartment wall (which is for a steam generator subcompartment) was 14 pounds per square inch. The design differential pressures across the subcompartment walls is substantially higher, with the minimum value being 19 pounds per square inch.

We have performed a confirmatory analysis of the applicants' 18 node subcompartment model for the steam generator compartment in order to evaluate the applicants' analysis. Using the applicants' input data and the COMPARE computer program, we obtained similar results. Therefore, we conclude that the applicants' analysis was performed in a reasonably conservative manner, and that the applicants' analysis is acceptable.

The applicants have also calculated the transient loads and moments acting on the reactor vessel, steam generators and reactor coolant pumps for use in the component supports design evaluations. The applicants have adequately justified the nodalization of major flow restrictions within the subcompartments. Furthermore, as stated above, the previously approved Westinghouse TMD code was used in the analysis.

We have reviewed the applicants' analysis and, in our judgment, an acceptable model has been developed for calculating asymmetric loads on components for use in evaluating the design of the component supports. Upon resolution of our generic Task A-2, "Asymmetric LOCA Loads," we will further review the subcompartment analysis to determine whether the Salem Unit 2 design is affected by any analytical or design requirements resulting from the resolution of generic Task A-2. Our discussion regarding the design capability of the reactor vessel and steam generator supports is presented in Section 3.9.1 of this report.

Main Steam Line Break Analysis

The applicants have analyzed a spectrum of main steam line break accidents to determine the containment pressure and temperature response. Various split breaks and double-ended ruptures at different power levels were postulated, assuming various single active failures. The Westinghouse modified COCO computer code was used in the analysis.

Mass and energy release for a spectrum of steam line breaks was calculated using the MARVEL code described in Topical Report WCAP-8860, "Mass and Energy Release Following a Main Steam Line Break." This report is currently under review by us. On the basis of our review of this report to date, we conclude that there is reasonable assurance that the mass and energy release rates will not be appreciably altered by completion of the analytical review.

The MARVEL code describes the primary and secondary systems of a pressurized water reactor including the power excursion which may occur in the core following a main steam line break. The code calculates heat flow from the core and intact steam generators into the primary system, and heat flow from the primary system into the broken steam generator. The primary system heat flow produces additional steam which is added to the containment. It is assumed that the flow from the break contains no liquid entrainment so that the break flow is all steam. This assumption permits the secondary liquid to remain in the steam generator until it is boiled by the heat transferred from the primary system, and maximizes the energy release. The analysis includes additional steam from the intact steam generators before closure of the isolation valves and from the unisolated steam in the steam lines and turbine plant piping. Feedwater flow is added to the affected steam generator based on the reduction in the discharge pressure calculated by the MARVEL code. No credit is taken for any feedwater flow reduction during the valve closure period. The unisolated feedwater mass is added to the steam generator inventory during the blowdown. On this basis, we have concluded that the mass and energy release data are acceptable for containment analysis of Salem Unit 2.

The applicants have identified the worst case main steam line break accidents to be a 0.860 square foot split break at 102 percent of full power for peak containment pressure (42.8 pounds per square inch gauge) and a 0.908 square foot split break at 70 percent of full power for the limiting containment temperature response (350 degrees Fahrenheit peak calculated temperature). The peak calculated pressure is lower than that for the design basis loss-of-coolant accident (43.2 pounds per square inch gauge) and is lower than the containment design pressure (47 pounds per square inch gauge).

For the above postulated pipe ruptures, the failure of an emergency bus to be energized was assumed, which resulted in the loss of one train of engineered safety features. For additional conservatism, feedwater addition to the affected steam generator was assumed to occur until the time of closure of the outboard isolation valve.

We have performed a confirmatory analysis of the 0.908 square foot main steam line break accident using the COMTEMPT-LT (MOD 26) computer code and the applicants' input data. The results of our analysis confirm the applicants' peak calculated temperature of 350 degrees Fahrenheit. Furthermore, the containment atmosphere temperature will remain above 300 degrees Fahrenheit for approximately three minutes. Therefore, we have determined that a temperature profile which remains above 300 degrees Fahrenheit for three minutes and at 350 degrees Fahrenheit for at least one minute is acceptable for use in equipment qualification for the Salem Unit 2 plant.

Based on our review of the applicants' main steam line break analysis and on our confirmatory analysis, we find the applicants' analysis to be acceptable.

6.2.3 Containment Isolation System

Since the issuance of Supplement 3 to the Safety Evaluation Report, the applicants provided additional information, by letters dated March 8, 1979 and October 5, 1979, regarding the closure times and operability of the purge system and pressure-vacuum relief system isolation valves under loss-of-coolant accident conditions.

The purge system, consisting of two 36-inch diameter lines, is designed to purge the containment atmosphere to improve personnel access. The pressure-vacuum relief system, consisting of one ten-inch diameter line, is designed to maintain the containment pressure within a prescribed range. These systems will not be used continuously; i.e., the two 36-inch diameter lines will be valved closed during all plant operations except refueling and cold shutdown, and the 10-inch diameter valves will be aligned such that the maximum open position will correspond to 60 degrees open instead of the original 90 degrees open. The applicants state that this valve alignment will significantly reduce the required closing torque, with a 60 pounds per square inch pressure differential (which is higher, and therefore more conservative, than the calculated pressure differential during a postulated accident), to a value well below the allowable actuator torque.

We have reviewed the purge system design for valve operability in the event of a postulated accident. On the basis of our review, we conclude that with regard to valve operability the design of the system is acceptable since (1) the valves in the 36-inch diameter lines will be closed during all plant operations except for refueling and cold shutdown, (2) the valves in the 10-inch diameter line will be aligned such that the maximum open position corresponds to 60 degrees, and (3) the torque required to close the valves in the 10-inch diameter line, in the event of an accident, is well below the allowable actuator torque.

We note that by letter, dated September 27, 1979 to all operating plants (including Salem Unit 1), we have provided guidelines regarding demonstration of the long-term operability of containment purge valves, and requested that information be provided in response to these guidelines. In the event that our review of these responses results in any changes to our requirements, the resultant changes would be imposed on Salem Unit 2 as appropriate.

As stated in Sections 6.2.3 and 15.4 of Supplement No. 3 to the Safety Evaluation Report, we were concerned about the time required for accomplishing system isolation following a postulated loss-of-coolant accident. The purge and pressure-vacuum relief system isolation valves are designed to close in two seconds following receipt of a safety injection signal, high containment pressure signal, or high radiation signal. The applicants have informed us that the total isolation time will not exceed five seconds if initiated by a high containment pressure signal, or 10 seconds if initiated by a high radiation signal.

The applicants have provided an analysis of the mass of steam released to the environs prior to purge system isolation following a loss-of-coolant accident (the analysis assumed that the valves in the two 36-inch diameter lines were initially open prior to the accident), and have included this potential radiation source in the radiological analysis for the site. Since the valves in the 36-inch diameter lines are closed during operation and since the pressure-vacuum relief system consists of a single ten-inch diameter line, calculations of the mass release based on the two 36-inch diameter purge system lines will be more conservative.

We have performed a confirmatory calculation of the mass release for the case where the high containment pressure signal (five pounds per square inch gage) initiates valve closure. Assuming a five-second isolation time, we estimate a steam release of about 6150 pounds. The release for this event is greater than that calculated for the case where only a high radiation signal initiates valve closure (assuming a 10-second isolation time) because the driving pressure in the containment will be substantially higher for the case of a high containment pressure signal.

We have also performed an independent evaluation of the radiological consequences based on the above release to the environs. The results of our evaluation are reported in Section 15.4 of Supplement No. 3 to the Safety Evaluation Report. In Section 15.4 of Supplement No. 3, we state that the combined loss-of-coolant accident dose, including the above purge, is calculated to be 70 rem thyroid and is within the guideline values of 10 CFR Part 100. Our basis for finding acceptable the operation of the pressure-vacuum relief system, as needed, during operating modes requiring containment integrity, namely, startup, power operation, hot standby or hot shutdown, is that the combined loss-of-coolant accident dose is within the guideline values of 10 CFR Part 100.

We have reviewed the entire purge and pressure-vacuum relief system against the guidelines of Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operation." We have determined that debris screens have been installed in conformance with these guidelines and that the system will isolate against containment pressure.

The applicants have also provided information relating to the reset isolation of the actuation signal for the pressure-vacuum relief system. In this regard, the applicants state the following:

(1) The containment ventilation isolation circuitry has been modified to include an additional safety injection input signal as part of the corrective action for the event identified in Salem Unit 1, Licensee Event Report 78-61. This signal is not included in the reset circuitry. Surveillance procedures will incorporate provisions to test the operability of both safety injection inputs to the containment ventilation isolation circuitry.

(2) The design will be revised to incorporate an alarm to indicate initiation of the containment purge and pressure-vacuum relief valve reset circuitry with an automatic actuating signal present. Operating procedures will be revised such that these valves will not be opened in an alarm condition, and will be immediately closed if they are open upon receipt of an alarm. This reset alarm will be installed prior to exceeding five percent power.

We have reviewed these features of the reset circuitry and conclude that they are acceptable since they will prevent inadvertent reset of the containment isolation signal.

On the basis of the above evaluations, we conclude that the containment purge system and pressure-vacuum relief system designs satisfy the provisions of Branch Technical Position CSB 6-4 and that operation of the systems as proposed is acceptable. We consider this matter resolved.

6.2.5 Containment Leakage Testing Program

In the Technical Specifications for Salem Unit 2, the applicants describe their proposed leak testing procedure for the containment airlocks, and propose an exemption from the associated requirements of Appendix J to 10 CFR Part 50. Based on our review, we find the proposed leak testing procedures and the proposed exemption to Appendix J acceptable. The rationale for our finding acceptable the applicants' proposed leak testing practices for the personnel airlocks and the proposed exemption from the associated requirements of Appendix J to 10 CFR 50, is discussed below.

Appendix J to 10 CFR 50 requires the containment personnel airlocks to be leak tested at six-month intervals and after each opening during such intervals (III.D.2). Appendix J further requires that the test be conducted at the peak calculated containment internal pressure related to the design basis accident (III.B.2).

Considering that a full pressure airlock test is to be performed every six months, it is our judgment that testing airlocks within three days after each opening or after the initial opening in a series of openings at the peak calculated containment internal pressure, as proposed by the applicants, will adequately demonstrate the continuing integrity of the airlock door seals such that the public health and safety will be ensured. The effect on accident consequences of testing after each opening versus testing within three days of an opening is judged to be insignificant. Furthermore, if an airlock door seal is damaged, it will be manifested during testing at the peak calculated containment internal pressure. This is an adequate demonstration of continuing airlock integrity for the period between the six-month tests.

We find that leak testing an airlock in the manner described above is an acceptable alternative to the requirements of Appendix J. Accordingly, the proposed exemption from the requirements of Appendix J is acceptable.

6.3 Emergency Core Cooling System

6.3.3 Performance Evaluation

In Section 6.3.3 of Supplement No. 3 to the Safety Evaluation Report, we concluded that the emergency core cooling system performance conformed to the criteria of 10 CFR 50.46 and was acceptable.

Subsequent to the issuance of Supplement No. 3, several issues were raised (i.e., the capacity of the refueling water storage tank, the net positive suction head for the emergency core cooling system pumps, the containment sump design, and switchover from the injection mode) all of which relate to the ability to establish the recirculation phase of cooling in the event of a loss-of-coolant accident. As a result we requested, and the applicants provided in several letters, additional information in order to resolve these issues. Our evaluation of these matters is presented below.

Refueling Water Storage Tank Capacity

At our request, the applicants have provided analyses to demonstrate the adequacy of the refueling water storage tank capacity to supply water to the emergency core cooling system pumps, in the event of a loss-of-coolant accident, until completion of the switchover from the injection mode to the recirculation mode of cooling.

The Technical Specifications for Salem Unit 2 will require a minimum volume of 364,500 gallons of water in the refueling water storage tank. Analyses based on the Salem Unit 2 sump geometry indicate that about 217,000 gallons of water are needed to flood the containment sump to an elevation of 81 feet, 7 inches which will provide adequate net positive suction head to the emergency core cooling system pumps from the sump lines (see discussion further below). To accommodate this water volume for the sump and considering instrument errors, the applicants will specify a low level alarm for the refueling water storage tank (to alert the operator to initiate the switchover procedure) at a level of 150,500 gallons. When the switchover procedure is initiated, the applicants have calculated that an additional 103,475 gallons of water would be depleted from the refueling water storage tank to complete switchover for the case of all pumps operating.

A backup alarm will also be provided at a water level of 119,000 gallons. Considering instrument error and unuseable volume in the refueling water storage tank (due to the elevation of the pump suction piping inlets), 108,300 gallons are available (as compared to the 103,475 gallons required) in the tank, when the backup alarm level is reached, to complete the switchover without impairing the net positive suction head to the pumps from the tank suction piping inlets. This amount of water has also been calculated to be sufficient to continue supplying the containment spray pumps.

The applicants have stated that the emergency core cooling system pump suction piping inlets from the refueling water storage tank are equipped with vortex suppression devices, which they have demonstrated to be effective in a pre-operational test.

We have reviewed the capacity of the refueling water storage tank, including the low level alarm settings, the analyses that have been performed to demonstrate adequacy, and the vortex suppression feature in the piping inlets. Based on our review, we conclude that the proposed water supply in the tank is adequate and, therefore, acceptable.

Net Positive Suction Head

At our request, the applicants have provided an analysis of the net positive suction head available to the emergency core cooling system pumps for a worst case condition.

The worst case condition was identified to be two residual heat removal system pumps each running at 4800 gallons per minute while taking suction from the containment sump during the recirculation mode following a postulated loss-of-coolant accident. This assumed pump capacity is conservative since discharge from the pumps would be limited to less than 4800 gallons per minute by orificing which has been installed in the discharge lines. Other assumptions include saturation conditions for sump water at atmospheric pressure (14.7 pounds per square inch and 212 degrees Fahrenheit) and that both outer and inner sump screens are 50 percent obstructed. Frictional head losses were calculated by using several standard reference handbooks and the highest calculated loss was assumed for each case.

The applicants provided pump head curves from the pump manufacturer (Ingersoll-Rand Company) to show that their treatment of head losses is consistent with the manufacturer's methodology in determining the required net positive suction head. The applicants also provided test results for both the No. 21 pump and the No. 22 pump in the residual heat removal system to show that their respective flow rates (4600 gallons per minute and 4300 gallons per minute) are within that assumed in the analysis (4800 gallons per minute).

Using the above assumptions, the applicants have calculated the margin of excess net positive suction head to be 2.6 feet for a sump flooding elevation of 81 feet 9 inches (and, hence, for the flooding elevation of 81 feet, 7 inches discussed above in the evaluation of refueling water storage tank capacity, the excess head would be 2.4 feet).

We have reviewed the applicants' calculations and conclude that there is adequate net positive suction head for the emergency core cooling system pumps.

Containment Sump Design

The sump screen design in the Salem Unit 2 containment sump incorporates vortex suppression techniques found to be effective in other pressurized water reactor designs. Because of the above consideration, there is reasonable assurance that, in the event of a loss-of-coolant accident, the Salem Unit 2 emergency core cooling system (i.e., residual heat removal system) pumps will function in the recirculation mode without damage due to air entrainment or vortices.

However, we require that the applicants perform model tests to verify the adequacy of the Salem Unit 2 sump design. These confirmatory results, along with a description of any sump modifications resulting from the tests, must be submitted prior to startup following the first refueling outage. In response to our request, the applicants have committed to such testing and have provided their proposed test program. We have reviewed the applicants' proposed test program and find that additional information is also needed for us to accept it. Specifically, we require the applicants to address the following areas:

(1) a statement of the tests' objective to confirm the current design or to correct it,

(2) identify the model scale, and

(3) provide more definition of the range of test parameters and conditions (i.e., the test matrix).

We will require that the above information be provided within 90 days after issuance of a low power license.

Switchover From Injection Mode to Recirculation Mode

In Section 7.3.6 of Supplement No. 1 to the Safety Evaluation Report, we concluded that the manual switchover procedure provided for the Salem plant, for changeover from the injection mode to the recirculation mode, was acceptable.

Subsequent to the issuance of Supplement No. 3 to the Safety Evaluation Report, we have reconsidered this matter and have established a requirement for Salem Unit 2 to provide an engineered safety feature design for automatic switchover from the injection mode to the recirculation mode. We have also rereviewed the manual switchover procedure and conclude that the procedure continues to be acceptable for full power operation, until the automatic switchover feature is installed.

The bases for this acceptance for the duration of the interim period are (1) a review of the applicants' analysis shows that there is time available for operator response in the manual mode and (2) the reduced likelihood of a loss-of-coolant accident during this time period.

We have informed the applicants of the above reconsideration and will require that, within 90 days after issuance of a low power license, the applicants submit the proposed conceptual design for automatic switchover, identifying each change, and a schedule for implementation.

7.0 INSTRUCTIONS AND CONTROL

7.2 Reactor Trip System

7.2.2 Anticipated Transients Without Scram

Background

In a pressurized water reactor, the anticipated transients which require prompt action to shut down the reactor in order to avoid plant damage and possible offsite effects can be classified in two groups: those that isolate the reactor from the heat sink, and those that do not. (A list of these transients is included in Appendix IV to Volume II of NUREG-0460, April 1978.) In general, the consequences of both of these types of events are an increase in reactor power or system pressure, or both. In Section 6.3 of NUREG-0460, Volume I, potentially unacceptable consequences of anticipated transients without scram events for pressurized water reactors of designs like Salem Unit 2 are indicated to include (1) pressure rises that could threaten the integrity of the reactor coolant pressure boundary, (2) loss of core cooling, and (3) leakage of radioactive material from the facility.

In NUREG-0460, we concluded that for plants which fall within the envelope of the Westinghouse generic anticipated transient without scram analyses, the anticipated transient without scram acceptance criteria will not be violated if the actuation circuitry of turbine trip and auxiliary feedwater systems which are relied upon to mitigate anticipated transient without scram consequences are sufficiently reliable and are separate and diverse from the reactor protection system. Additionally, the functionability of valves required for long-term cooling following the postulated anticipated transient without scram events has to be demonstrated.

The NRC's Regulatory Requirements Review Committee has completed its review and concurred with our approach described in Volume 3 of NUREG-0460 insofar as it applies to Salem Unit 2. We issued requests for the industry to supply generic analyses to confirm the anticipated transient without scram mitigation capability described in Volume 3 of NUREG-0460. The staff evaluation of these reports was issued for comment as NUREG-0460, Volume 4, in March 1980.

We plan to present our recommendations on anticipated transients without scram to the Commission in May 1980, including the recommendations for modifications contained in Volume 4 of NUREG-0460. The Commission would determine required modifications to resolve anticipated transient without scram concerns as well as the required schedule for implementation of such modifications. Salem Unit 2 would, of course, be subject to the Commission decision in this matter.

The following discusses the bases for operation of Salem Unit 2 at power levels not exceeding five percent while final resolution of anticipated transients without scram is before the Commission.

In NUREG-0460, Volume 3, we state: "The staff has maintained since 1973 (for example, see pages 69 and 70 of WASH-1270) and reaffirms today that the present likelihood of severe consequences arising from an ATWS event is acceptably small and presently there is no undue risk to the public from ATWS. This conclusion is based on engineering judgment in view of: (a) the estimated arrival rate of anticipated transients with potentially severe consequences in the event of scram failure; (b) the favorable operating experience with current scram systems; and (c) the limited number of operating reactors."

In view of these considerations and our expectation that the necessary plant modifications will be implemented in one to four years following a Commission decision on anticipated transients without scram, we have generally concluded that pressurized water plants can continue to operate because the risk from anticipated transient without scram events in this time period is acceptably small. As a prudent course, in order to further reduce the risk from anticipated transient without scram events during the interim period before completing the plant modifications determined by the Commission to be necessary, we have required that the following steps be taken:

(1) Emergency procedures be developed to train operators to recognize an anticipated transient without scram event, including consideration of scram indicators, rod position indicators, flux monitors, pressurizer level and pressure indicators, pressurizer relief valve and safety valve indicators, and any other alarms annunciated in the control room with emphasis on alarms not processed through the electrical portion of the reactor scram system.

(2) Operators be trained to take actions in the event of an anticipated transient without scram, including consideration of manually scramming the reactor by using the manual scram button, prompt actuation of the auxiliary feedwater system to assure delivery of the full capacity of this system, and initiation of turbine trip. The operator should also be trained to initiate boration by actuation of the high pressure safety injection system to bring the plant to a safe shutdown condition.

We consider these procedural requirements an acceptable basis for interim operation of the Salem Unit 2 plant based on our understanding of the plant response to postulated anticipated transient without scram events.

In response to our requirements on operator training and emergency procedures, the applicants submitted on March 14, 1980, emergency operating procedures for the postulated anticipated transient without scram events.

Although the proposed procedures need to be revised to be acceptable for full power operation, it is our judgment that the Salem Unit 2 plant may be operated at low power (less than or equal to five percent of full power) prior to completion of procedure modifications without undue risk to the health and safety of the public. Therefore, we have concluded that the plant can be safely operated at low power prior to completion of this effort because of the expected plant response to relevant anticipated transient without scram events at power levels not exceeding five percent (see Task Action Plan A-9).

7.9 Loss of Non-Class 1E Instrumentation and Control Power System Bus During Operation

On November 30, 1979, the Office of Inspection and Enforcement issued IE Bulletin No. 79-27, "Loss of Non-Class 1E Instrumentation and Control Power System Bus During Operation," to all power reactor facilities with an operating license and to those nearing licensing. This bulletin outlined actions to be taken to address control system malfunctions and significant loss of information to the control room operator as a potential consequence of the loss of 120 Vac control power to these plant systems. Further, IE Information Notice No. 80-10, issued on March 7, 1980, provided information relating to the Crystal River Unit 3 event of February 26, 1980, in which a significant loss of information to the operator resulted from a loss of power to a portion of the plant instrumentation system.

At this time the applicants have not completed their review of this matter. However, the control and instrument systems for Westinghouse plants such as Salem Unit 2 utilize reactor protection measurements, with suitable isolation devices, for a large portion of the measurements used by the plant control systems. This arrangement provides an additional degree of redundancy in information available to the operator. Further, the number of control systems which would be placed in automatic control for plant operation up to five percent power would be significantly reduced under this mode of operation, and therefore operation up to five percent power is acceptable. We will require resolution of this matter before operation above five percent power.

8.0 ELECTRIC POWER

8.2 Offsite Power System

8.2.1 Grid Stability

In Supplement No. 3 to the Safety Evaluation Report, we stated that insufficient information had been presented to substantiate whether the effects of disturbances on the grid are more severe during light load conditions or during the maximum projected seasonal peak load conditions.

Since the issuance of Supplement No. 3 to the Safety Evaluation Report, the applicants have submitted information to support their contention that light load conditions, rather than peak load conditions, represent a more pessimistic state for evaluating transient stability of the electrical grid. The applicants listed three major factors which result in light load conditions and which constitute a more severe test in terms of evaluating transient stability. These are: lower system inertia, higher system impedance and lower generator excitation.

Based on our review of the applicants' results of the transient stability analysis for light load conditions, and on our discussions with the applicants on this subject as documented in our minutes of the meeting held on October 24-25, 1978, we conclude that there is reasonable assurance that the loss of the most critical power source, load or inter-tie will not affect stability of the Public Service Electric and Gas Company's grid or the ability to provide offsite power to the Salem station. This satisfies the criteria set forth in Section 8.2 of the Standard Review Plan and, therefore, is acceptable.

8.2.2 Electrical Independence of the Offsite Power System

We reported in Supplement No. 3 to the Safety Evaluation Report that, in the event of a loss of power to the offsite power transformer which feeds two emergency buses, the failure of a single relay in the control circuits of the in-feeder breakers connecting this transformer to the emergency buses will frustrate the transfer of two emergency buses to the other transformer.

We also expressed concern in Supplement No. 3 to the Safety Evaluation Report about a failure in the automatic transferring scheme of the non-safety related group buses which may result in the simultaneous loss of both offsite power circuits and the capability to satisfy the delayed access offsite power circuit requirements set forth in Criterion 17 of the General Design Criteria. We requested that the applicants perform an audit of this aspect of the design and either demonstrate that the design meets the requirements of Criteria 17 and 18 of the General Design Criteria, or modify the design accordingly.

Furthermore, it was reported in Supplement No. 3 to the Safety Evaluation Report that a decision has not been reached with regard to whether the design of the automatic transfer of safety and non-safety buses from one transformer to the other conforms with Criterion 17 of the General Design Criteria.

Since the issuance of Supplement No. 3 to the Safety Evaluation Report, the applicants have provided information which indicates that the failure of a single relay will only prevent the automatic transfer of a single emergency bus (instead of two buses as originally reported) from one offsite power transformer to the other. Our review of this aspect of the design determined that there is an independent automatic transfer scheme associated with each of the three emergency buses. Thus, a single failure in one of the automatic transfer circuits can only prevent the transferring of one bus from one transformer to the other. The transfer of at least one bus to the other transformer will assure that the minimum redundancy required of the safety systems is maintained when the offsite power system is supplying power to the emergency buses. Based on our review of the design depicted in the electrical diagrams, we could not find a failure which could frustrate the transfer of two emergency buses to the other transformer. Therefore, we conclude that this matter is of no further concern.

With regard to the possibility of single failures in the automatic transferring scheme of non-safety buses from the unit auxiliary transformer to the offsite power transformers, our review of the results of the audit performed by the applicants confirmed that the design of the automatic transferring scheme of non-safety buses is not vulnerable to single failures. The design of each pair of in-feeder breakers associated with each non-safety bus provides for two diverse, but not independent, interlocks to eliminate the possiblity of having both breakers closed at the same time and, therefore, prevents the paralleling of the transformers. Although the two interlocks are not independent and a single failure can disable both of them, there are other features in the design independent of these interlocks which will assure that both breakers are not closed at the same time. Based on our review of the design depicted in the electrical diagrams, we could not postulate a failure which could lead to the simultaneous loss of both offsite power circuits or the loss of capability to satisfy the delayed access offsite power circuit requirements set forth in Criterion 17 of the General Design Criteria. Therefore, we consider this matter resolved.

In conclusion, the existing design for the offsite power system satisfies the criteria set forth in Section 8.2 of the Standard Review Plan which includes conformance with Criteria 17 and 18 of the General Design Criteria and, therefore, is acceptable.

8.3 Onsite Power Systems

8.3.1 Alternating Current Power Systems

(3) Diesel Generator Protection Trips

In Supplement No. 3 to the Safety Evaluation Report, we stated that the applicants had inadequately justified the non-conformance of the design with the positions set forth in Branch Technical Position ICSB (PSB) 17, "Diesel Generator Protective Trip Circuit Bypasses" of Appendix 8-A of the Standard Review Plan. We required that the design of each protective trip in each diesel generator, with the exception of engine overspeed and generator differential, be bypassed upon detection of an emergency situation or have at least two or more independent measurements of each trip parameter with the trip logic requiring specific coincidence.

The applicants have elected to bypass all the equipment protective trips associated with the engine and generator breaker of each diesel generator set except for the overspeed, primary and backup generator differential, four kilovolt bus differential and low oil pressure trips during loss of offsite power and accident conditions. The low oil pressure trip requires the coincidence actuation of two oil pressure switches to produce a trip.

We have reviewed the design modifications and conclude that the design as depicted in the revised electrical diagrams satisfies the positions set forth in Branch Technical Position ICSB (PSB) 17 and, therefore, is acceptable.

8.3.2 Direct Current Power Systems

(3) 125 Volt Direct Current Onsite Emergency Power System, 230/115 Volt Alternating Current Vital System and 28 Volt Direct Current Vital System Interconnections

In Supplement No. 3 to the Safety Evaluation Report, we stated that, with regard to the interconnections between redundant divisions in the 125 volt direct current emergency power system and in the 28 volt direct current vital system, the applicants had not adequately demonstrated the capability of the design to withstand a fire event without the loss of capability to achieve cold shutdown. We also stated that the resolution of this issue would be pursued with the applicants during the fire hazards analysis review.

In this regard as part of the fire hazards analysis review, we required the applicants to examine each interconnection within and between these systems and to either demonstrate the capability of the design to withstand a fire event without the loss of capability to achieve hot and cold shutdown, or modify the design accordingly.

The applicants have elected to institute administrative controls that will preclude the two redundant and independent feeder breakers associated with each interconnection from being closed at the same time. Safety or non-safety loads associated with each interconnection will receive power via one feeder breaker at a time. In our review of this matter, we have determined that having only one feeder breaker closed at a time will minimize the probability of a fire event at an interconnection from compromising the independence between redundant divisions. Thus, the capability for achieving hot and cold shutdown will be assured. We conclude that this issue has been satisfactorily resolved.

In Supplement No. 3 to the Safety Evaluation Report, we stated that we required that design modifications be made in the 125 and 28 volt direct current systems to prevent any two redundant divisions in each of these systems from being fed by battery chargers which receive input power from the same 230 volt alternating current bus, or that Technical Specifications limit the time during which these systems are fed by battery chargers which receive input from the same alternating current bus. The applicants have selected the Technical Specifications approach in lieu of design modifications. This satisfies the stated requirement and, therefore, is acceptable.

(4) Interconnection of the 125 Volt Direct Current Emergency Systems Between Units

In Supplement No. 3 to the Safety Evaluation Report, we expressed concern about the interconnections of the 125 volt direct current emergency systems between units. We required that the applicants either demonstrate the capability of the interconnection design to withstand a fire event without the loss of capability to achieve cold shutdown in each unit, or modify it accordingly.

The applicants have proposed to institute administrative controls that will assure that the two feeder breakers, associated with each interconnection and through which power is supplied from either unit to the interconnecting bus, will not be closed at the same time. In our review of this matter, we have determined that having only one feeder breaker closed at a time will minimize the probability of a fire event at an interconnection from compromizing the independence between redundant divisions in each unit. Thus, the capability for achieving cold shutdown will be assured. We conclude that this issue has been satisfactorily resolved.

8.3.4 Diesel Generator Reliability

The reliability of the installed diesel generators has been demonstrated by performance of the preoperational testing specified in Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants." This includes performance of 69 consecutive start and load tests with zero failures, and a 24 hour full-load-carrying capability test. A continuing demonstration of reliability will be obtained by inclusion in the Technical Specifications of the periodic testing provision of Regulatory Guide 1.108.

in the design to provide an alternative capability to achieve hot and cold shutdown in the event a fire disables the normal capability for safe shutdown presently provided in the switchgear, relay, or main control rooms. Our findings and conclusions pertaining to these matters are included in our evaluation of the fire protection program, which is attached as Appendix E to this supplement.

8.4.7 Electrical Requirements Associated with the Seal Cooling Water for the Reactor Coolant Pumps

In Supplement No. 3 to the Safety Evaluation Report, we stated that we had not been able to determine whether the control and motive power connections to the valves in the component cooling water lines to the reactor coolant pump seals are physically and electrically independent of those connections to the valves in the chemical and volume control system lines to the reactor coolant pump seals. We required that the applicants perform an audit of the design to determine whether a single electrical failure could cause the loss of the two sources of cooling water to the reactor coolant pump seals.

The valves in the component cooling water and chemical and volume control system lines to the reactor coolant pump seals receive motive and control power from three redundant and independent buses. The audit performed by the applicants indicates that the motive and control circuits of these valves have been distributed among these three buses in a manner that would preclude a single electrical failure from causing a total loss of cooling water to any reactor coolant pump. All these valves are normally open and capable of being operated manually from the control room. The valves in the supply and return lines to and from the reactor coolant pump seals in the component cooling water system and chemical and volume system are used as containment isolation valves. The valves in the chemical and volume control system will be automatically closed by a high containment pressure signal (referred to as Phase A containment isolation). The valves in the component cooling water lines will automatically isolate the correspondent piping upon receipt of a high-high containment pressure signal (referred to as Phase B containment isolation). The Phase A and Phase B signals are considered independent of each other.

We have reviewed the applicants' audit results and verified that the design, as presented in the piping and instrument diagrams and electrical and logic diagrams, supports the applicants' findings in this regard. Based on our review of the design as depicted in the aforementioned diagrams, we could not postulate a single failure or spurious signal in the motive and control power supplies or in the manual and automatic isolation circuits associated with these valves which could result in the total loss of cooling water to the reactor cooling pumps. Therefore, we conclude that the design is acceptable.

8.4.8 Environmental Qualification of Electrical Equipment

In Supplement No. 3 to the Safety Evaluation Report, we identified a number of open items on environmental qualification of safety related Class 1E equipment for which additional information would be required. The applicants have submitted responses to our concerns by letters dated March 6, 8, 16, and 30, 1979, July 17, 1979, and August 28, 1979. The following presents our evaluation of these open items.

The applicants have calculated what the environmental conditions would be inside containment following a design basis main steam line break accident. As discussed in Section 6.2.1 of this report, we have performed a confirmatory analysis of the postulated accident using the applicants' input data. The results of this analysis indicate that the bounding equipment qualification temperature for equipment located inside containment is 350 degrees Fahrenheit at 43 pounds per square inch gauge minimum. It was also determined that a temperature profile which remains at 350 degrees Fahrenheit for at least one minute and above 300 degrees Fahrenheit for three minutes, superimposed on the temperature profile for the loss-of-coolant accident, is accceptable for equipment qualifications for Salem Unit 2. The pressure and temperature profiles for the loss-of-coolant accident are given in Figures 7.5-4 and 7.5-5 respectively of the Final Safety Analysis Report. Acceptable qualification for the loss-of-coolant accident radiation environment is 200 megarads.

The results of our review of this information are summarized as follows:

(1) Electrical Terminal Blocks

The terminal blocks were irradiated to 200 megarads, assembled in their design ungasketed junction boxes, wired to 140 volt alternating current and direct current power sources (about 117 percent of design rating) and appropriate loads, and the assemblies were environmentally tested for the loss-of-coolant accident and main steam line break accident environments. The test profiles (except for the leading edge of the temperature transient) enveloped the conditions of the loss-of-coolant accident and main steam line break environments including the above cited main steam line break qualification requirements, with margin. The fact that the leading edge of the test temperature transient reached the specified calculated temperature in 20 seconds instead of 10 seconds is not considered significant in view of the overall margins included in the tests. These tests are documented in Conax Corporation Report No. IPS-400. We have reviewed the test data in this report and conclude that the environmental qualification of the terminal blocks for both loss-of-coolant accident and main steam line break conditions is acceptable.

(2) Electrical Cables

For cables not tested to the new main steam line break peak temperature, the applicants reported the results of a thermal analysis for cables in a temperature profile which bounds the main steam line break temperature profile. The results of this analysis indicated that the calculated peak surface temperature of the cable was 333 degrees Fahrenheit. This cable irradiated to a total dosage in excess of that encountered in a main steam line break had previously been successfully tested to 340 degrees Fahrenheit for three hours. Since the

To provide further assurance of the long term reliability of the diesel generators, the applicants have been requested to review the design with regard to the recommendations of NUREG/CR 0660, "Enhancement of Onsite Emergency Diesel Generator Reliabilty," and to report the conformance to or plans for implementation of these recommendations or justiciation for the exisiting design. In a letter dated February 14, 1980, the applicants provided the requested information. We will review this information prior to full power operation and require implementation of these recommendations as deemed necessary prior to the start of operation after the first refueling cycle, to assure long term reliability of the installed diesel generators.

8.4 Other Electrical Features and Requirements for Safety

8.4.1 Offsite and Onsite Emergency Power Systems Interactions

(1) Position 1 - Second Level of Undervoltage Protection

In Supplement No. 3 to the Safety Evaluation Report, we stated that we required the applicants to comply with this position by documenting their modified design and by committing to install the second level of undervoltage protection prior to the first refueling outage.

Since the issuance of Supplement No. 3 to the Safety Evaluation Report, the applicants have submitted revised electrical diagrams depicting how the second level of undervoltage protection will be implemented in the existing design. Each of the three redundant and independent alternating current emergency buses will use an undervoltage relay in series with a timer to implement the second level of undervoltage protection. The output from the timer in each bus will be connected in parallel with the output from first level of undervoltage protection in that bus. The output from either of the two levels in each bus will energize three auxiliary relays. One auxiliary relay output from each bus will be combined in a two-out-of-three matrix with its redundant counterparts from the other two buses. One of the three two-out-of-three matrices thus formed is assigned to each emergency bus. The output from the two-out-of-three matrices signifies that an undervoltage condition has occurred on at least two buses. This intelligence is input to each of the three independent safeguards equipment controllers which will act to disconnect the offsite power sources from the emergency buses.

We have reviewed the design modifications as depicted in the electrical diagrams and conclude that they satisfy this position and, therefore, are acceptable. Moreover, the applicants have committed to install the second level of undervoltage protection during the first refueling outage. Our Office of Inspection and Enforcement will verify that the design modifications are implemented in accordance with our requirements. We conclude that this issue has been satisfactorily resolved.

8.4.3 Reactor Containment Electrical Penetrations

In Supplement No. 3 to the Safety Evaluation Report, we stated that we required the applicants to either demonstrate that the penetration associated with each load is designed to sustain faults indefinitely without imparing the integrity of the penetration itself, or that the design provide for independent primary and backup protective relays and breakers to interrupt the fault current to the corresponding load within the specified time.

The applicants have provided information which indicates that each containment electrical penetration circuit will be protected by independent primary and backup detecting and interrupting devices. The applicants have performed an integrity analysis of the electrical penetrations to verify the capability of each backup protective device to interrupt the maximum available short circuit current prior to exceeding the thermal limits of the associated electrical penetration assembly. The results of this analysis have demonstrated the capability of the backup protection devices to perform their intended function except for 12 circuits fed from 230 volt alternating current motor control centers. The applicants have proposed to add a fuse in series with the primary device of each one of these 12 circuits to provide the backup protection required. Each fuse will be located in an independent compartment in the control center of the present primary device.

The applicants have committed to implement these design modifications before completion of the first refueling outage. We do not anticipate any problems in the implementation of these design modifications and conclude that the design proposed is acceptable. Our Office of Inspection and Enforcement will verify that the modifications are implemented in accordance with our requirements.

Based on our confirmatory review of the results of the applicants' integrity analysis of the electrical penetrations as depicted on fault current versus time curves, we conclude that the overall design of the electric penetrations as well as the proposed modifications satisfy our requirements and, therefore, are acceptable. These requirements are set forth in Criterion 50 of the General Design Criteria, as augmented by Institute of Electrical and Electronics Engineers Standard 317-1972, "Electrical Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations," and Regulatory Guide 1.63, "Electrical Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants."

8.4.5 Compliance with Regulatory Guide 1.75, "Physical Independence of Electrical Systems" (Revision 1)

In Supplement No. 3 to the Safety Evaluation Report, we stated that we had not completed our review of the cable installation conformance with the recommendations of Regulatory Guide 1.75. The matters of minimum separation between redundant cable trays and flame tests performed to demonstrate the adequacy of the cable arrrangement were pursued during our review of the fire hazards analysis. As a result of our review of these matters, the applicants have committed to make the necessary modifications test temperature was higher than the calculated peak surface temperature, we conclude that the cable is qualified for the main steam line break environment.

The applicants submitted Franklin Institute Research Laboratories Report No. F-C5115 to substantiate requalification for the loss-of-coolant accident environment for control and instrumentation cables manufactured by American Insulated Wire Corporation. Requalification was necessary because the prior testing had been performed on samples irradiated to only 100 megarads. The retesting was performed on both thermally aged and unaged samples with a total irradiated dose of 200 megarads. We have reviewed the test report and conclude that this cable is qualified for the loss-of-coolant accident environment.

The applicants have also summarized (on Table Q7.30 of the Final Safety Analysis Report) the results of the environmental qualification of all vital electrical cable located in containment, including identification of the applicable documentation. On the basis of our review of this summary, and of the above cited additional information submitted, we conclude that the environmental qualification of all vital electrical cable located in containment for both loss-of-coolant accident and main steam line break conditions is acceptable.

(3) Motor Operated Valves

The applicants reported the results of a thermal analysis performed on Westinghouse supplied motor operated valves which are included in the Westinghouse requalification program. The analysis was performed using the same main steam line break temperature profile, model, assumptions and technique as discussed above for cables. The maximum surface temperature of the motor operated valves, limit switch compartment was calculated to be 291 degrees Fahrenheit. We have also reviewed the environmental qualification test reports including the test data for these valve operators. This information substantiates qualification of this equipment to approximately 340 degrees Fahrenheit and 200 megarads. Therefore, we conclude that these motor operated valves are qualified for both the loss-of-coolant accident and main steam line break environment.

(4) Fan Cooler Motor

We have reviewed the results of a thermal analysis performed on this equipment to demonstrate qualification for the main steam line break environment. We also compared these analysis results with those of the analysis performed on similar equipment in the Diablo Canyon Plant, Units 1 and 2 (Docket Nos. 50-275 and 50-323). The results of the calculations demonstrated that the motor winding temperature (cooling air inlet plus winding temperature rise) will not exceed qualified levels for the winding hot spot temperature when the motor is subjected to the main steam line break environment. We conclude on the basis of this review, and on the basis of our prior review of test information supporting qualification for the loss-of-coolant accident environment, that the fan cooler motors are qualified for both the loss-of-coolant accident and main steam line break environment.

On this basis of our evaluation as discussed above, we consider the matter of environmental qualification of electrical equipment to be resolved.

8.4.9 Seismic Qualification of Electrical Equipment

In Section 3.10 of Supplement No. 3 to the Safety Evaluation Report, we stated that the adequacy of the seismic qualification program will be reviewed by the NRC seismic qualification review team. Since the issuance of Supplement No. 3 to the Safety Evaluation Report, the seismic qualification review team has conducted an audit review of the equipment installation and seismic qualification documentation at the site.

This section supplements Section 3.10 of this report where the overall subject of seismic qualification of Category I instrumentation and electrical equipment is discussed. This section presents the results of the audit review of the functional monitoring aspects of seismic qualification of electrical equipment. The records of the following items of electrical equipment were audited: (1) 460 and 230 volt alternating current motor control centers and switchgear, (2) five kilovolt alternating current switchgear, (3) 125 volt direct current distribution cabinets and switchgear, (4) 28 and 125 volt batteries and chargers, (5) electrical penetrations, (6) vital instrument bus static inverters, and (7) diesel generator control cabinets.

Our audit review at the site had found acceptable the qualification information with regard to the verification of the safety function during and after seismic testing for the items listed above, with the exception of the 28 and 125 volt battery chargers and certain electrical protective relays associated with the five kilovolt switchgear and the diesel generator control cabinets. Subsequently, additional test information on these items was submitted for our review which confirmed the capability of this equipment to perform its safety function. Therefore, we conclude that the seismic qualification of the safety related electrical equipment is acceptable.

9.0 AUXILIARY AND EMERGENCY SYSTEMS

9.4 Fuel Handling System

In Section 9.4 of Supplement No. 3 to the Safety Evaluation Report, we stated that our review of the Salem Unit 1 license amendment change request to expand the spent fuel pool, which was still in progress, would determine the acceptability of the proposed design changes for the Unit 1 and Unit 2 spent fuel pools.

Subsequent to the issuance of Supplement No. 3 to the Safety Evaluation Report, we completed our review of the expanded spent fuel pool for Salem Unit 1 and determined that it is acceptable. Our evaluation of this matter is presented in Appendix D to this report. Based on our review of the modifications to the Unit 1 spent fuel pool and on the fact that the two fuel pools are identical, we conclude that the proposed modifications of the Unit 2 spent fuel pool are acceptable.

9.7 Fire Protection System

In Section 9.7 of Supplement No. 3 to the Safety Evaluation Report, we stated that the applicants had conducted a re-evaluation of their proposed fire protection system for Salem Nuclear Generating Station, Units 1 and 2 and that we were reviewing the applicants fire protection analysis in accordance with Appendix A to Branch Technical Position Auxiliary System Branch 9.5-1 (BTP ASB 9.5-1), "Guidelines for Fire Protection for Nuclear Plants." We also stated that our evaluation would be completed prior to a decision concerning the issuance of an operating license for Unit 2.

We have now completed our review of the fire protection program and fire hazards analysis for Salem Units 1 and 2. As part of the review, we visited the plant site to examine the relationship of safety related components, systems, and structures in specific plant areas to both combustible materials and to associated fire detection and suppression systems. The overall objective of our review of the fire protection program was to ensure that in the event of a fire at either facility, Units 1 and 2 would maintain the ability to safely shutdown, remain in a safe shutdown condition, and minimize the release of radioactivity to the environment. Our safety evaluation regarding this matter for both Units 1 and 2 was issued on November 20, 1979, and is attached as Appendix E to this report.

Our review included an evaluation of the automatic and manually operated water and gas fire suppression systems, the fire detection systems, fire barriers, fire doors and dampers, fire protection administrative controls, fire brigade training, and plant fire protection Technical Specifications.

Our conclusion, as given in Section VII of Appendix E, is that the fire protection program for Salem Units 1 and 2 is adequate at the present time, and meets Criterion 3 of the General Design Criteria. However, to further ensure the ability of the plant to withstand the damaging effects of fires that could occur, we are requiring, and the applicants have agreed to provide, additional fire protection system improvements. Until the committed fire protection system improvements are operational, we consider the existing fire detection and suppression systems; the existing barriers between fire areas, improved administrative procedures for control of combustibles and ignition sources, the trained onsite fire brigade, the capability to extinguish fires manually, and the fire protection Technical Specifications provide adequate protection against a fire that would threaten safe shutdown. These additional fire protection features will be completed for Unit 2 prior to completing its first refueling outage. The schedule for specific protection system improvements is presented in Table I of Appendix E.

12.0 RADIATION PROTECTION

Subsequent to the issuance of Supplement No. 3 to the Safety Evaluation Report, an evaluation of the Salem radiation protection organization, staffing and qualifications was performed by an NRC Health Physics Appraisal Team during the period of January 28 through February 8, 1980. As a result of this evaluation, the team made the following findings:

(1) The majority of the radiation protection program for normal, off-normal and emergency situations was being implemented by contractor personnel, who constituted approximately 80 percent of the radiation protection staff.

(2) Though contractor technician personnel in responsible positions had two years experience in radiation protection, as required by Regulatory Guide 1.8, "Personnel Selection and Training," none had formal training by the applicants (i.e., Public Service Electric and Gas Company) or the contractor.

(3) Because of the transient nature of employment with contractor organizations, the average length of time that contractor technician and supervisory personnel were at Salem was six months. This resulted in the majority of the elements in the radiation protection program being implemented by personnel not formally trained or retrained in radiation protection and who had limited experience and familiarization with the facility, and led to a situation where essentially all of the technical and management expertise was vested in the Radiation Protection Manager (who is part of the applicants' organization).

(4) There was no back-up for the Radiation Protection Manager to function in his absence.

(5) The plant organization was set up so that the Supervisor, Chemistry and Health Physics (Radiation Protection Manager) reported through the Performance Engineer to the Station Manager, rather than directly to the Station Manager.

In order to correct the above situation, the applicants have committed to actions to provide a permanent solution for staffing the radiation protection organization with applicant employees and to provide interim steps to assure that contractor personnel receive adequate training, and to assure that there is a back-up to the Radiation Protection Manager.

The applicants have made long-term commitments to reorganize the radiation protection organization so that the staff can acquire training and experience in radiation protection in a shorter period of time than is required now. Currently these individuals rotate to assignments other than those in radiation protection, thus extending the time necessary to become qualified. Elimination of rotation will allow applicant employees to become qualified to assume the duties now performed by contractor personnel. Because this reorganization may change the functions of technicians from chemistry, instrument and control, and radiation protection to solely radiation protection, the applicants must negotiate the changes with the technicians' union. The applicants have committed to provide to the NRC, by no later than July 1, 1980, the reorganization plan, including target dates. This reorganization will be reviewed prior to issuance of a full power license. In addition, the applicants have committed to employ onsite an individual, with the qualifications specified in Regulatory Guide 1.8 for the Radiation Protection Manager, to function as a back-up to the Radiation Protection Manager.

In the interim, the applicants have committed to provide all contractor radiation protection personnel a formal indoctrination program that will require such personnel to demonstrate their general radiation protection knowledge, to verify their accumulated working experience, and that will provide training in plant procedures and other site-specific information. The applicants will not allow contractor personnel to perform duties for which they have not been trained and qualified to the same standards applied to applicant personnel. In addition, the applicants have committed to include long-term contractor personnel in their annual technician retraining and requalification program. The applicants will stabilize the contractor supervisors in their positions by requiring that such individuals give 30 days notice prior to terminating their assignment at the Salem plant. Until an individual is selected as the onsite back-up to the Radiation Protection Manager, a qualified corporate health physicist has been assigned to maintain adequate communication with the Radiation Protection Manager to assure a working understanding of current station and personnel status so that the corporate health physicist can function as the Radiation Protection Manager in his extended absence.

However, the proposed reorganization would maintain the Radiation Protection Manager reporting through the Performance Engineer to the Station Manager. The Draft Criteria for Utility Management and Technical Competence specifies that the Radiation Protection Manager should report directly to the Plant Manager. In addition, Regulatory Guide 8.8, "Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations will be as Low as is Reasonably Achievable," states that the Radiation Protection Manager should have direct recourse to the Plant Manager in order to resolve questions related to the conduct of the radiation protection program. Therefore, we require that the Radiation Protection Manager have direct access to the Station Manager for matters of radiological health and safety dealing with policy determination, interpretation and implementation (based on the judgment of the Radiation Protection Manager).

On the basis of our evaluation, and subject to the Radiation Protection Manager having direct access to the Plant Manager as discussed above, we conclude that the above actions will provide an acceptable radiation protection staff.

13.0 CONDUCT OF OPERATIONS

13.1 Plant Organization, Staff Qualification and Training

13.1.1 Training Programs

All personnel licensed to operate Salem Unit 1 and applicants to be administered Salem Unit 2 examinations have received the following TMI-2 related training:

(1) the TMI-2 accident;
(2) the differences between Salem Unit 1 and Unit 2;
(3) methods of hydrogen and void formation in the core;
(4) methods of core heat removal including natural circulation flow; and
(5) training in the new vendor guidelines covering emergencies.

Public Service Electric and Gas Company administered its own examination on TMI-2 related subjects, plant modifications and procedure changes to all operators and senior operators licensed on Salem Unit 1. All personnel received 90 percent or greater on the initial examination or the reexamination. The test has been audited and the grading certified by NRC personnel. No deficiencies were noted.

Public Service Electric and Gas Company has 19 operators who have applied for a license (ten senior operator applicants and nine operator applicants) to operate the controls of the Salem Unit 2. Of this group, eight hold senior reactor operator licenses and nine hold reactor operator licenses on Salem Unit 1; the remaining two operators are applying for senior licenses on Salem Units 1 and 2.

NRC examinations were administered to the ten senior operator and nine operator applicants during January and February 1980. The examinations were expanded in scope to cover thermodynamics, fluid flow and heat transfer. The passing grade was 80 percent overall and no less than 70 percent in each category. All individuals, except one operator who terminated employment, were administered oral examinations.

Eight applicants passed the senior operator examination and four passed the operator examination. All of the senior operators and reactor operators have previous operating experience on a commercial pressurized water reactor. The average operating experience for the senior operators is three years with a minimum of one and one half years of experience. The average operating experience for the reactor operators is two and one half years with a minimum of one year of experience.

All the individuals meet the new requirements for issuance of licenses enumerated in the Action Plan and SECY-79-330E, "Qualificaton of Reactor Operators to Sit for a Cold Examination," except for administration of simulator examinations and separate categories for fluid flow, heat transfer and thermodynamics. The examinations were administered prior to the Commission's decision on implementation of SECY-79-330E, which requested implementation of the augmented requirements in the above areas as soon as possible. However, we find that the individuals involved have demonstrated sufficient knowledge and understanding in their examinations to conclude that they can operate the facility in a safe and competent manner.

Based on the above examination results, the Salem plant has the following complement for operation of Units 1 and 2:

Number	Type of License
8	Unit 1 and 2 Senior Operator Licenses
4	Unit 1 and 2 Operator Licenses
22*	Unit 1 Senior Operator Licenses
15*	Unit 1 Operator Licenses

Our shift manning requirements for two unit operation are discussed in Section I.A.1.3 of Part II to this supplement. The number of licensed operators, shown above, for Salem Unit 2 is not sufficient to meet those requirements for operation in Mode 1, 2, 3 or 4. Although the number is sufficient to load fuel on Unit 2, it is not sufficient to go critical.

In Section 15.2.4 of this supplement, we present our evaluation of, and requirements for, testing in Mode 5 (cold shutdown) after fuel loading and before there is a sufficient number of licensed operators to go critical.

We conclude that the Public Service Electric and Gas Company's training programs are designed to, and are progressing toward, producing individuals who are qualified to meet the upgraded requirements in SECY-79-330E.

13.2 Emergency Planning

In Section 13.2 of Supplement No. 3 to the Safety Evaluation Report, we stated that the applicants' Emergency Plans should be revised to provide for a General Emergency Class which is solely and directly associated with the Class 4 Emergency of the States of New Jersey and Delaware, and for which initiation of protective actions in at least the low population zone would be recommended by the applicants. We also stated that we require that the States Emergency Classes 1, 2, and 3, which require

*Two senior operators and four operators licensed on Salem Unit 1 failed the Salem Unit 2 examination. All the operators (including the senior operators) who failed the Salem Unit 2 examination will not perform licensed duties at Salem Unit 1 until they have completed accelerated training in deficient areas and have been reexamined per the requirements of the Salem licensed operator requalification program.

various notifications and possibly notification for off-site assessment, fall under the applicants' site or station emergency classes.

In letters dated December 21, 1978 and January 8, 1979, the applicants provided revisions to their Emergency Plans which conform satisfactorily to our requirements. We find that these plans now conform to the applicable staff positions of Regulatory Guide 1.101, Revision 1, "Emergency Planning for Nuclear Power Plants" and Appendix E to 10 CFR Part 50, and provide reasonable assurance that appropriate measures can and will be taken in the event of an emergency to protect the public health and safety and prevent damage to property. Our evaluation of the emergency plans for five percent power and our requirements for full power operation are discussed in Section III.B.1 of Part II to this supplement.

14.0 TEST AND STARTUP PROGRAM

In Section 14.0 of Supplement No. 3 to the Safety Evaluation Report, we concluded that the test program was acceptable with the following exceptions:

(1) The applicants provided insufficient information for us to conclude that testing would be conducted in accordance with Regulatory Guide 1.41, "Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments."

(2) The applicants provided insufficient information for us to conclude that elimination of the turbine trip test from 100 percent power was justified. This test is addressed in Regulatory Guide 1.68, November 1973, "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors."

(3) The applicants provided insufficient information for us to conclude that preoperational testing would be conducted in accordance with Regulatory Guide 1.108, August 1977, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants."

(4) The applicants provided insufficient information for us to conclude that testing would be conducted in accordance with Regulatory Guide 1.68.2, Revision 1, July 1978, "Initial Startup Test Program to Demonstrate Remote Shutdown Capability for Water-Cooled Nuclear Power Plants."

In a letter dated February 5, 1979 regarding these matters, the applicants provided the following additional information:

(1) With respect to Regulatory Guide 1.41, the applicants have committed to perform testing in accordance with this Regulatory Guide.

(2) With respect to the turbine trip test, the applicants provided analyses of the turbine trip and the generator load reject events for Salem Unit 2. The analyses showed that the latter event would impose a more severe transient on the facility therefore eliminating the need for the turbine trip test. The basis for this conclusion is that the generator load reject test that will be conducted will not result in a direct prompt reactor scram. The method used to initiate the opening of the generator output breakers will result in delayed reactor scram (approximately five to seven seconds). We have reviewed this information and other information provided by the applicants relating to the design of the turbine trip logic and generator trip logic. On the basis of our review, we conclude that the generator trip event would impose a more severe

plant transient and therefore conduct of the turbine trip test, which would cause a prompt reactor scram, is not necessary for this facility.

(3) With respect to Regulatory Guide 1.108, the applicants have committed to preoperationally test the diesel generators in accordance with this regulatory guide, except for positions C.2a(4) and C.2a(6). Position C.2a(4) recommends testing to verify the capability of the deisel generator to withstand a loss of the single largest load and total loss of load without exceeding design voltage levels and without initiating an overspeed trip. The applicants' proposed alternative for position C.2a(4) is to demonstrate total loss of load for each diesel generator (opening of the generator output breaker) to assure that design voltage levels are not exceeded and to assure that the diesel generator does not trip on overspeed. We find this acceptable because the kilowatt loading of the diesel generator prior to the trip will be in excess of the total design emergency loads and thus would impose a more severe test than the guide recommends. Position C.2a(6) recommends that testing be conducted to demonstrate live transfer of emergency loads from the diesel generators to offsite power sources. Since the applicants' design will not permit live transfers, we conclude that this position is not applicable to Salem Unit 2.

(4) With respect to Regulatory Guide 1.68.2, the applicants have committed to preoperationally test in accordance with this regulatory guide except for position C.4. Position C.4 recommends that testing be conducted to demonstrate the ability to cool down the reactor from hot standby to a cold shutdown condition from locations outside the main control room. The applicants have proposed to develop a detailed procedure and to trial test the procedure prior to initial fuel loading. The applicants have also provided a summary of the cooldown procedure for our review. We have reviewed the summary of the cooldown procedure and conclude that the alternative proposed above provides reasonable assurance that cooldown could be accomplished from outside the control room and is therefore acceptable.

On the basis of our review as discussed above, we conclude that the initial test program for the Salem Unit 2 is acceptable.

In a letter dated November 9, 1979, the applicants proposed deferring some preoperational tests until after fuel loading and, in two cases, until after initial criticality. The tests include testing of one main steam safety valve (prior to initial criticality), initial synchronization of the main generator, and testing of three of six circulators in the main condenser for the circulating water system (prior to exceeding 50 percent power).

We have reviewed the deferral of preoperational tests proposed by the applicants in their letters and find this proposal to be acceptable provided that the tests are conducted prior to the times indicated in the applicants' letters. The basis for acceptance is that the deferral will not affect the safe operation of the plant.

15.0 ACCIDENT ANALYSES

15.1 General

15.1.1 Normal Operation and Anticipated Operational Transients

The analysis methods for postulated transients and accidents are normally reviewed in a generic sense. In this regard, we have received submittals from Westinghouse for the loss-of-coolant accident, main steamline break accident, feedwater line break accident, and rod ejection accident. The description of the computer programs used in the analysis of these accidents have also been submitted.

The loss-of-coolant accident and rod ejection accident reviews have been completed and the analysis methods were found acceptable. Our safety evaluation is documented in letters dated August 28, 1973 and May 30, 1975. The steamline and feedline break reviews are presently underway. The status of the code reviews, as well as the ongoing steamline break and feedline break reviews, are discussed below:

(1) The following topical reports have been approved:

   (a) WIT-6 (WCAP-7980, "Reactor Transient Analysis Computer Program Description") - Approved August 30, 1976

   (b) THINC IV (WCAP-7956, "An Improved Program in Thermal and Hydraulic Analysis of Rod Bundle Cores") - Approved April 19, 1978

   (c) PHOENIX (WCAP-7973, "Calculation of Flow Coastdown after Loss of Reactor Coolant Pump") - Approved March 31, 1977

(2) The LOFTRAN, FACTRAN, MARVEL and BLKOUT code topical reports are currently under review by us. These analysis methods are described in WCAP-7907 "LOFTRAN Code Description," WCAP-7908 "FACTRAN - A FACTRAN IV Code for Thermal Transients in a UO_2 Fuel Rod," WACP-7909 "MARVEL - A Digital Computer Code for Transient Analysis of a Multi-Loop PWR System," and WCAP-7898 "Long Term Transient Analysis Program for Pressurized Water Reactors (BLKOUT)," respectively. Our review of these topical reports has progressed to the point that there is reasonable assurance that the conclusions based on these analyses will not be appreciably altered by completion of the analytical review, and therefore that there will be no effect on the decision to issue an operating license. If the final approval of these topical reports indicates that any revisions to the analyses are required, Salem Unit 2 will be required to implement the results of such changes.

(3) Main Steamline and Feedline Breaks - Westinghouse has recently submitted topical reports which present its analysis methods and sensitivity studies for postulated main steamline and feedline breaks. This information is contained in WCAP-9226, "Reactor Core Response to Excessive Secondary Steam Releases," for steamline breaks and WCAP-9230, "Report on the Consequences of a Postulated Main Feedline Rupture," for feedline breaks. In addition, WCAP-9236, "NOTRUMP - A NODAL Transient Steam Generator and General Network Code," was submitted which discusses the NOTRUMP computer program. This code is used in the analyses of the postulated feedline breaks. Initially the review of these topical reports were scheduled for completion in late 1979. For the review of the steamline break topical report, we requested additional information from Westinghouse in September 1978. Westinghouse responded with answers to some of our questions in May 1979. In response to our inquiries, Westinghouse has attributed its failure to answer the balance of our questions to higher priority TMI-2 analyses requirements.

We have previously accepted steamline and feedline break analyses described in plant applications for pressurized water reactors designed by Westinghouse and other reactor vendors. It has been our position that a more detailed account of analytical methods for steamline and feedline break is required from the vendors for generic review and that the outcome of this review would be applied to licensed reactors. Our generic review includes the performance of in-house audit calculations and calculations by technical assistance contractors.

While our review of the above reports is not sufficiently advanced to provide complete assurance that the Salem Unit 2 analysis methods are acceptable, it does provide evidence that substantial thermal margin exists under postulated steamline and feedline break accident conditions to preclude core damage leading to unacceptable consequences. Therefore, we conclude that the steamline and feedline break accident analyses for Salem Unit 2 are acceptable while our more detailed review continues.

Our approval is predicated on the assumption that our generic review can proceed on a reasonable schedule. To assure that this occurs, we will require a timely response to our outstanding questions on the topical reports discussed above, and a commitment for prompt response to additional information requirements. The responses to outstanding questions and a commitment to provide a prompt response to additional information requirements should be provided prior to approval of a full power operating license, but it is not necessary that the staff complete its review and issue an evaluation for these codes and analyses prior to approval of a full power operating license.

15.2 Design Basis Accident Assumptions

15.2.4 Boron Dilution Accident

As discussed in Section 13.1.1 of this supplement, the applicants currently do not have a sufficient number of reactor operators licensed on Salem Unit 2 to permit operation of Unit 2 in Mode 1, 2, 3 or 4. Therefore, until additional reactor operators are licensed on Unit 2, the unit can not be operated beyond Mode 5 (cold shutdown). The number of licensed operators is sufficient to load fuel in the reactor but is not sufficient to go critical.

The Technical Specification conditions for Mode 5 require an effective multiplication factor of less than 0.99 and an average coolant temperature equal to or less than 200 degrees Fahrenheit. For Mode 6 (refueling), the Technical Specification require an effective multiplication factor equal to or less than 0.95 and an average coolant temperature equal to or less than 140 degrees Fahrenheit. The effective multiplication factor requirement for Mode 6 is assured by using reactor coolant having a boron concentration of 2000 parts per million.

In order to perform tests on Salem Unit 2 in Mode 5 after fuel loading and before criticality, we require that the applicants maintain the reactor coolant system at the boron concentration level of Mode 6 (2000 parts per million). Although the control rods will not be removed, this boron concentration will insure that the effective multiplication factor will not exceed 0.95 with all the control rods removed.

Should a boron dilution accident start, the operator would have in excess of one hour to terminate deboration before the reactor becomes critical. In addition, there are several alarms on the borating system which would alert the operator to the condition. Furthermore, the source range instrumentation is active and would provide a positive indication in the control room of any significant reduction in the coolant system boron concentration. We, therefore, conclude that this mode of operation provides adequate assurance that the reactor cannot inadvertantly be made critical.

17.0 QUALITY ASSURANCE

17.1 General

Our review of the quality assurance program description for the operations phase for Salem Unit 2 has verified that the criteria of Appendix B to 10 CFR Part 50 have been adequately addressed in Sections D.1, D.2, and D.5 of the Final Safety Analysis Report through Amendment 43. This determination of acceptability included a review of the list of safety related structures, systems, and components (Appendix C to the Final Safety Analysis Report) to which the quality assurance program applies. We have recently developed a revised procedure for conducting the Q-list review that involves other technical review branches within the Office of Nuclear Reactor Regulation and significantly enhances the staff's confidence in the acceptability of Appendix C. Staff re-review of Appendix C using the revised procedure is presently underway and the results will be reported in a later supplement. This re-review is not considered to be of sufficient importance to require its completion prior to granting authority to load fuel and perform low power tests.

18.0 REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The Advisory Committee on Reactor Safeguards completed its review of the application for the Salem Nuclear Generating Station, Unit 2 at its 226th meeting held on February 8-10, 1979. A copy of the Committee's report for Salem Unit 2, dated February 15, 1979 and revised on February 22, 1979, is attached as Appendix B. The actions we have taken or plan to take in response to these comments and recommendations are described in the following paragraphs:

(1) The Committee stated that in its review of Salem Unit 1 and of the Hope Creek units at the same site, concern was expressed about the possibilities of accidents involving waterborne traffic on the Delaware River that might be of such nature as to affect the safety of the plants. The Committee further stated that it continues to be concerned about accidents of this nature and believes that the potential hazards should continue to be reviewed from time to time as local conditions may change and as the extent and reliability of the data base may be increased.

As a result of an Atomic Safety and Licensing Appeal Board Decision, dated January 12, 1979, the Hope Creek construction permits (Docket Nos. 50-354 and 50-355) have been amended to include conditions designed to ensure that we will be promptly alerted should circumstances arise which suggest that the risk from flammable gas clouds (resulting from river traffic accidents) may increase to unacceptable levels. Because of the close proximity of the Salem Units to Hope Creek Station, these monitoring and reporting requirements will provide information directly relevant to Salem Unit 2 and provide reasonable assurance that we will be made aware of any unfavorable developments in river transportation of flammable materials.

In addition, the NRC's Office of Inspection and Enforcement reviews with licensees, on a three-year cycle, matters relating to changes that may have occurred in the land use in the site vicinity (Inspection Procedure No. 30702B, July 1, 1977). These include potential hazards from external sources.

(2) The Committee recommended that the NRC staff establish criteria for the implementation of Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," as soon as practicable. The Committee believes that position C.3 of this guide should be implemented on Salem Unit 2 to the extent practicable.

As stated in Section 1.1 of Supplement 3 to the Safety Evaluation Report, we have not yet established the criteria for implementation of the recommendations specified in Regulatory Guide 1.97. At such time as we determine guidance for implementation of this guide, it will be applied to Salem Unit 2 to the extent practicable. This matter is further discussed in Section II.F.1 of Part II to this supplement.

(3) The Committee stated that with regard to the generic items cited in the Committee's report, "Status of Generic Items Relating to Light-Water Reactors: Report No. 6," dated November 15, 1977, those items considered relevant to Salem Unit 2 are: II-2, 3, 5B, 6, 7, 9, 10; IIA-2, 3, 4; IIB-2, IIC-1, 2, 3A, 3B, 4, 5, 6; IID-1, 2; IIE-1. These matters should be dealt with by the NRC staff and the applicants, as appropriate, when solutions are found.

Our discussion of generic matters identified by the Committee is presented in Appendix C to Supplement No. 3 to the Safety Evaluation Report.

21.0 FINANCIAL PROTECTION AND INDEMNITY REQUIREMENTS

21.3 Operating License

Supplement No. 1 to the Safety Evaluation Report addressed the financial protection and indemnity requirements for the Salem Nuclear Generating Station, Units 1 and 2.

10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements," has been amended to increase the amount of primary financial protection required for facilities having a rated capacity of 100 electrical megawatts or more from $140 million to $160 million. (44 Fed. Reg. 20632, April 6, 1979.) This amendment became effective May 1, 1979.

On the basis of the above considerations and those identified in our Safety Evaluation Report and Supplement No. 1 thereto, we conclude that the presently applicable requirements of 10 CFR Part 140 have been satisfied and that prior to issuance of the operating license for Salem Unit 2, the applicants will be required to comply with all of the provisions of 10 CFR Part 140 applicable to operating licenses, including those as to proof of financial protection in the requisite amount and as to execution of an appropriate indemnity agreement with the Commission.

APPENDIX A

CONTINUATION OF CHRONOLOGY OF RADIOLOGICAL REVIEW OF SALEM NUCLEAR GENERATING STATION, UNIT 2

December 15, 1978	Letter to applicant requesting additional information - Auxiliary Systems Branch, fire protection positions.
December 18, 1978	Letter from applicant transmitting responses to NRC Questions 1.48, 5.96, 5.110 and 14.28.
December 21, 1978	Representatives from PSE&G and the NRC met in Bethesda, Maryland to discuss Salem Unit 2 fire protection program. (Summary of Meeting issued January 4, 1979).
December 21, 1978	Letter from applicant transmitting responses to NRC Questions 1.41, 5.108, 7.29, 12.23, 14.26 and revised portions of FSAR Section 12.9.
December 29, 1978	Issuance of Supplement No. 3 to the Salem Safety Evaluation Report.
January 4, 1979	Letter from applicant transmitting the Inservice Testing Program for pumps and valves.
January 4, 1979	Letter from applicant transmitting responses to NRC Questions 7.35, 9.59, 13.9(a), 13.9(b), 13.9(c) and 13.9(d).
January 4, 1979	Summary of December 21, 1978 meeting held with applicant concerning fire protection program.
January 8, 1979	Letter from applicant responding to NRC questions related to emergency action levels.
January 12, 1979	Letter to applicant transmitting copies of Supplement No. 3 to the Salem Safety Evaluation Report.
January 12, 1979	Westinghouse letter transmitting a report entitled, "Fuel Grid Impact Loads for Salem Unit No. 2" on Salem Unit 2 docket and requesting that it be withheld from public disclosure as proprietary.

January 18, 1979	Letter from applicant transmitting responses to NRC Questions 4.38, 5.96, 5.110, 13.9, and on quality assurance and subcompartment analysis.
January 19, 1979	Letter to applicant requesting additional information - Auxiliary Systems Branch.
January 22, 1979	Letter to applicant withholding proprietary material from public disclosure - AW-78-84 and AW-77-27 - a report entitled "Dynamic Analysis of the Reactor Coolant System for Loss of Coolant Accidents: Salem Nuclear Generating Station, I and II".
January 22, 1979	Letter to applicant withholding proprietary material from public disclosure - Tables 5.62 and 5.82 - CAW-78-81 and AW-76-29.
January 29, 1979	Summary of January 24, 1979 ACRS Subcommittee Meeting.
January 31, 1979	NRC and PSE&G representatives met at the Salem Unit No. 2 site to discuss fire protection program.
February 5, 1979	Letter from applicant transmitting responses to NRC Question 13.9.
February 6, 1979	Letter from applicant transmitting the response to NRC Question 5.9.
February 12, 1979	Letter from applicant concerning a request for exemption - 10 CFR 50, Appendix G.
February 13, 1979	Summary of February 8, 1979 ACRS Committee Meeting.
February 13, 1979	Letter from applicant concerning request for deferment for incomplete items.
February 14, 1979	Letter to applicant concerning Contents of the Offsite Dose Calculation Manual.
February 15, 1979	ACRS Report on Salem Nuclear Generating Station, Unit 2.
February 22, 1979	Revision to ACRS letter on Salem. The ACRS forwarded a new page 3.
February 26, 1979	Letter to applicant transmitting the ACRS Report to utility.
February 26, 1979	Letter to applicant withholding from public disclosure a report entitled "Fuel Grid Impact Loads for Salem Unit No. 2".

February 26-28, 1979	Representatives from NRC visit the Salem Unit 2 site to discuss seismic qualification of safety related equipment and to perform site audit.
March 1, 1979	Letter to applicant transmitting a revised page 3 to the ACRS Report on Salem Unit No. 2.
March 2, 1979	Generic letter to applicant transmitting NUREG-0523, "Summary of Operating Experience with Recirculating Steam Generators."
March 2, 1979	Letter from applicant transmitting responses to NRC requests for additional information on fire protection.
March 5, 1979	Representatives from NRC and PSE&G met in Bethesda, Maryland to discuss Salem Unit 2 Technical Specifications. (Meeting Summary dated March 7, 1979)
March 6, 1979	Letter from applicant transmitting responses to NRC requests for additional information regarding sufficient auxiliary feedwater in the event of a tornado missile strike.
March 6, 1979	Letter from applicant transmitting a report entitled, "Evaluation of the Reactor Coolant System Considering Subcompartment Pressurization Following a LOCA for Salem Units No. 1 and 2."
March 8, 1979	Letter from applicant transmitting updated responses to requests for additional information (Questions 5.66 and 7.32).
March 16, 1979	Letter from applicant transmitting responses to the environmental qualification items listed in Section 8.48 of Supplement No. 3 to the Safety Evaluation Report.
March 19, 1979	Letter from applicant transmitting Contingency Plan for Salem Nuclear Generating Station, Units 1 & 2.
March 23, 1979	Letter from applicant transmitting responses to questions concerning seismic qualification.
March 28, 1979	Letter from applicant concerning request for deferment for incomplete items.
March 29, 1979	Letter from applicant transmitting additional information in the form of revised pages to its report "Evaluation of the Reactor Coolant System Considering Subcompartment Pressurization Following a LOCA for Salem Units 1 and 2."

March 30, 1979	Letter from applicant transmitting responses to NRC Questions 7.29 (seismic qualification), 7.30 (equipment qualification), 8.4.8(4) (qualification of fan cooler motor), Position 40 (fire protection) and Question 14.31.
March 30, 1979	Letter from applicant requestion extension of construction completion date for Unit No. 2, Construction Permit CPPR-53. The completion date expires on May 1, 1979 and the applicant requests an extension to August 1, 1979.
April 11, 1979	Letter from applicant transmitting responses to the seismic qualification data for electrical, instrumentation and mechanical components.
April 11, 1979	Letter from applicant transmitting a revised response to NRC Question 13.9 part (d) related to remote shutdown capability.
April 11, 1979	Letter from applicant transmitting additional information related to the seismic qualification of the 600 volt switchgear.
April 23, 1979	Letter to applicant concerning channelhead cracking.
April 23, 1979	Letter from applicant transmitting a revision to the radiation monitoring system.
April 24, 1979	Letter from applicant transmitting a report entitled "Structural Integrity Test of Containment."
April 24, 1979	Letter from applicant concerning valve weights used in seismic analysis.
April 30, 1979	Letter from applicant transmitting the 1978 Annual Report for Salem Units 1 and 2.
May 1, 1979	Letter to applicant requesting additional information with respect to extension of the construction completion date for Salem Unit 2.
May 2, 1979	Letter from applicant transmitting General Electric's supplement test data related to the 5KV switchgear relays 12HFA51A42F, 12IAC66B6A and 12IAV74A1A.
May 3, 1979	Applicant transmits the amended Salem security plan.
May 4, 1979	Letter from applicant concerning the deferment of incomplete items.

May 9, 1979	Representatives from NRC and PSE&G met in Bethesda, Maryland to discuss the seismic qualification program. (Summary of meeting issued June 1, 1979).
May 15, 1979	Letter from applicant concerning rod drop analysis.
May 17, 1979	Letter from applicant transmitting responses regarding the NPSH for the RHR pumps.
May 23, 1979	Letter from applicant transmitting excerpts from Wyle Laboratories Seismic Qualification Test Report Nos. 43815-1 and 44079-1, which are applicable to Salem's 600 volt switchgear.
May 23, 1979	Letter from applicant transmitting responses to information requested and a steam generator schematic diagram.
May 30, 1979	Letter from applicant advising that construction and preoperational testing of Unit 2 has been substantially completed and that the unit is ready for initial fuel loading, testing and operating.
June 1, 1979	Letter to applicant concerning instrumentation qualification (request for additional information).
June 13, 1979	Letter to applicant concerning preoperational testing of Salem Unit 2.
June 14, 1979	Representatives from PSE&G and NRC met in Bethesda, Maryland to discuss Salem Unit 2 steam generator cladding. (Summary of meeting issued June 26, 1979.)
June 19, 1979	Letter from applicant transmitting $1200 for the fee for construction extension of Salem Unit 2.
June 25, 1979	Letter from applicant concerning the delay in licensing of Salem Unit 2.
June 27, 1979	Representatives from PSE&G and NRC met in Bethesda, Maryland to discuss the lessons learned from the TMI accident and its impact on the issuance of an operating license for Salem Unit 2. (Summary of meeting issued July 10, 1979).
June 28, 1979	Letter from applicant transmitting additional information in support of a request for extension of Construction Permit No. CPPR-53.
July 6, 1979	Letter from applicant transmitting listings of items including pre-operational tests.

July 13, 1979	Letter from applicant concerning rod drop analysis.
July 16, 1979	Letter from applicant transmitting responses to the seismic qualification data for electrical, instrumentation and mechanical components.
July 17, 1979	Letter from applicant transmitting copies of the Conax Environmental Qualification Test Report on Electrical Terminal Blocks.
July 18, 1979	Letter from applicant transmitting updated listings of items including pre-operational tests which may not be complete until after initial fuel loading. This information updates the transmittal of July 6, 1979.
July 19, 1979	Letter from applicant concerning the steam generator channel head inspection.
July 23, 1979	Letter to applicant concerning IE Bulleting No. 79-07, "Seismic Stress Analysis of Safety Related Equipment".
July 25, 1979	Representatives from PSE&G and NRC met in Bethesda, Maryland to disucss the ACRS Subcommittee meeting regarding the Three Mile Island Accident as it relates to Salem Unit 2. (Summary of meeting issued August 1, 1979.)
July 30, 1979	Letter to applicant concerning a request for additional information for the review of the Salem Unit 2 FSAR.
July 31, 1979	Letter to applicant concerning secondary chemistry control.
August 7, 1979	Letter from applicant conerning IE Bulletin No. 79-07 and schedule for reevaluation of Salem Unit 2.
August 7, 1979	Letter from applicant transmitting a report - Franklin Research Center Environmental Qualification Test Report for Electrical Cables (American Insulated Wire).
August 16, 1979	Letter from applicant concerning security training and qualification plan.
August 17, 1979	Representatives from NRC and PSE&G met in Bethesda, Maryland to discuss matters regarding IE Bulletin No. 79-02.
August 17, 1979	Letter to applicant concerning Interim Actions Needed for Plant Operation Pending Final Resolution of ATWS.

August 22, 1979	Letter to applicant requesting additional information - engineered safety features.
August 28, 1979	Letter from applicant responding to NRC Question 3.13, concerning fuel assembly grid strap damage.
August 28, 1979	Letter from applicant responding to a request for supplemental information - Section 8.4.8, Item 2 of Supplement 3 to the Safety Evaluation Report.
August 28, 1979	Letter from applicant concerning proposed license condition on secondary water chemistry control.
August 31, 1979	Letter to applicant requesting additional information on the FSAR (Question 4.39).
September 7, 1979	Letter to applicant requesting additional information on Section 3.0 of the FSAR.
September 21, 1979	Letter to applicant requesting additional information on Section 5.0 of the FSAR.
September 28, 1979	Letter to applicant requesting additional information on the FSAR.
October 4, 1979	Letter from applicant responding to additional information concerning RHR pumps.
October 10, 1979	Letter from applicant concerning Adequacy of Station Electric Distribution System Voltages.
October 11, 1979	Letter to applicant concerning environmental qualification of Class 1E instrumentation and electrical equipment.
October 12, 1979	Letter to applicant concerning an assessment of the Salem Unit 2 containment sump.
October 12, 1979	Letter from applicant transmitting responses to Short Term Lessons Learned and Emergency Preparedness.
October 17, 1979	Letter to applicant concerning ATWS.
October 18, 1979	Letter to applicant concerning environmental qualification of reactor coolant temperature detectors and containment pressure transmitters.
October 19, 1979	Letter to applicant requesting additional information - NPSH requirements for RHR pumps.

October 22, 1979	Letter from applicant concerning response to request for additional information on steam generator level measurement errors.
October 23, 1979	Letter to applicant transmitting an Order extending the construction completion date for Salem Unit 2 to May 1, 1980.
October 23, 1979	Letter from applicant concerning evaluation of potential malfunctions due to high-energy line breaks.
October 23, 1979	Letter from applicant concerning a request for additional information -environmental qualification of instrumentation.
November 6, 1979	Letter from applicant concerning emergency instructions.
November 8, 1979	Letter from applicant concerning responses to NRC questions regarding refueling water storage tank capacity.
November 8, 1979	Letter from applicant concerning containment purge and pressure-vacuum relief valves.
November 9, 1979	Letter from applicant concerning revised request for deferment on incomplete items.
November 19, 1979	Letter from applicant concerning an updated emergency plan.
November 20, 1979	Representatives from Sequoyah, Diablo Canyon, Salem & North Anna met with NRC representatives in Bethesda, Maryland to discuss the auxiliary feedwater system requirements.
November 21, 1979	Letter to applicant concerning upgraded emergency plans.
November 23, 1979	Letter to applicant concerning proposed Revision 2 to Regulatory Guide 1.97 "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident."
November 26, 1979	Letter from applicant concerning Lessons Learned Short Term Requirements.
November 29, 1979	Letter to applicant concerning separation of electrical equipment and systems at nuclear power plants.
December 11, 1979	Representatives from PSE&G and NRC met in Bethesda, Maryland to discuss matters regarding Lessons Learned Task Force recommen-

	dations as they relate to Salem. (Summary of meeting issued December 17, 1979.)
December 13, 1979	Representatives from Salem, North Anna, Diablo Canyon, Sequoyah, McGuire, Farley, Summer, San Onofre and Watts Bar met with NRC representatives in Bethesda, Maryland to discuss draft Revision 2 to Regulatory Guide 1.97. (Summary of meeting issued January 11, 1980.)
December 14, 1979	Letter to applicant concerning implementation of the recommendations of NUREG-0660, "Enhancement of Onsite Emergency Diesel Generator Reliability."
December 21, 1979	Letter to applicant concerning environmental monitoring for direct radiation.
December 21, 1979	Letter to applicant concerning emergency response plans.
December 26, 1979	Letter to applicant concerning request for information regarding evacuation times.
January 4, 1980	Letter from applicant transmitting Submittal 2 of the contingency plan.
January 4, 1980	Letter from applicant submitting its revised responses to requests for additional information contained in NRC letters, dated September 27, 1979 and November 9, 1979.
January 8, 1980	Letter from applicant transmitting the response to NRC Question 4.39, "Use of the WESAN Computer Code in the Subcompartment Analysis."
January 9, 1980	Letter to applicant concerning inservice testing of pumps and valves.
January 10-11, 1980	Site visit to Salem to discuss matters regarding Lessons Learned Task Force with representatives from PSE&G and NRC.
January 11, 1980	Letter to applicant requesting additional information on initial tests.
January 15, 1980	Letter from applicant concerning containment sump design drawings attached.
January 31, 1980	Letter from applicant concerning emergency planning efforts.
January 31, 1980	Letter from applicant transmitting responses to auxiliary feedwater flow questions.

January 31, 1980	Letter to applicant concerning secondary water chemistry monitoring program.
February 5, 1980	Representatives from PSE&G, VEPCO, PG&E and NRC met in Bethesda, Maryland to discuss low power test program for Diablo Canyon, Salem and North Anna. (Summary of meeting issued February 8, 1980.)
February 7, 1980	Trip Report on meeting held at Salem site on January 30 and 31, 1980 to review the Salem inservice testing program for pumps and valves.
February 8, 1980	Letter from applicant concerning special low power test program.
February 11, 1980	Letter to applicant regarding a position revision on testing requirements of the Power Systems Branch.
February 12, 1980	Letter to applicant concerning single dropped rod events.
February 14, 1980	Letter from applicant concerning degradation of guide thimble tube walls.
February 14, 1980	Letter from applicant responding to NRC letter concerning emergency diesel-generator reliability.
February 19, 1980	Letter to applicant concerning change in review procedures for equipment qualification documentation.
February 21, 1980	Letter to applicant concerning qualification of safety-related electrical equipment.
February 25, 1980	Representatives from PSE&G and NRC met in Bethesda, Maryland to discuss matters related to RWST capacity. (Summary of Meeting issued March 13, 1980.)
February 26, 1980	Representatives from VEPCO, PSE&G, TVA, PG&E and NRC met in Bethesda, Maryland to discuss requirements in the design review of plant shielding and environmental qualification of equipment for spaces/systems which may be used in post accident operations for Diablo Canyon, Salem 2, North Anna 2 and Sequoyah.
February 26, 1980	Letter from applicant concerning single dropped rod events.
February 27, 1980	Representatives from NRC and PSE&G met at the Salem site to discuss matters regarding outstanding TMI and non-TMI related issues. (Summary of Meeting issued March 11, 1980.)

March 3, 1980	Representatives from NRC, VEPCO and PSE&G met in Bethesda, Maryland to discuss requirements for fuel loading and low power testing on North Anna 2 and Salem 2. (Summary of Meeting issued March 6, 1980.)
March 6, 1980	Letter from applicant transmitting Amendment No. 43 to the Final Safety Analysis Report.
March 6, 1980	Letter from applicant concerning control room design review.
March 10, 1980	Letter to applicant concerning NRC Bulletins and Orders Task Force review regarding the TMI Unit 2 accident.
March 10, 1980	Letter to applicant concerning an interim upgrade of emergency planning regulations.
March 11, 1980	Letter to applicant concerning a change of submittal date for evacuation time estimates.
March 13, 1980	Letter to applicant concerning potential design deficiencies in bypass, override, and reset circuits of engineered safety features.
March 13, 1980	Letter from applicant concerning full load testing of vital buses.
March 13, 1980	Letter from applicant concerning ATWS procedures.
March 13, 1980	Letter from applicant concerning RHR system, NPSH for pumps and RWST capacity.
March 14, 1980	Letter from applicant concerning secondary water chemistry control program.
March 17, 1980	Letter to applicant concerning baseline hydraulic data.
March 17, 1980	Letter to applicant concerning low power test program - simulated loss of all AC power test.
March 19-21, 1980 24-25	Representatives from NRC, Essex Corporation & PSE&G met at the Salem Site to discuss matters related to Salem Unit 2 control room.
March 27, 1980	Letter to applicant concerning steam generators for Salem Unit 2.

March 28, 1980	Letter from applicant concerning additional information on containment purge and pressure-vacuum relief system.
March 28, 1980	Letter from applicant concerning steam generator level set-points for refueling water storage tank alarms.
March 28, 1980	Letter from applicant concerning a response to IE Bulletin No. 79-06C.
March 28, 1980	Letter from applicant concerning TMI-2 Lessons Learned.
March 28, 1980	Letter from applicant requesting an extension of the construction completion date for Salem Unit 2 to November 1, 1980.
March 28, 1980	Letter from applicant concerning the review of NUREG-0611.
March 31, 1980	Letter from applicant requesting special low power test program.
April 1, 1980	Letter from applicant concerning degraded core-training.
April 3, 1980	Letter from applicant concerning TMI Lessons Learned.
April 3, 1980	Letter from applicant concerning management for operations.
April 3, 1980	Letter from applicant concerning changeover from injection to recirculation mode of ECCS cooling.
April 3, 1980	Letter from applicant concerning RHR system, NPSH for pumps and RWST capacity.
April 4, 1980	Representatives from Public Service Electric and Gas Company, Virginia Electric and Power Company, Tennessee Valley Authority, Pacific Gas and Electric and NRC met in Bethesda, Maryland to discuss applicants' progress and status in the design review of plant shielding and environmental qualification of equipment.
April 7, 1980	Letter from applicant concerning RWST low level alarm setpoints.
April 9, 1980	Letter from applicant concerning licensed operator coverage.
April 14, 1980	Letter from applicant concerning plant procedures for shift supervisors in the event of an emergency.
April 15, 1980	Letter from applicant concerning corporate management technical support in the event of an emergency.

APPENDIX B

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

February 15, 1979

Honorable Joseph M. Hendrie
Chairman
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: REPORT ON SALEM NUCLEAR GENERATING STATION UNIT 2

Dear Dr. Hendrie:

During its 226th meeting, February 8-10, 1979, the Advisory Committee on Reactor Safeguards completed its review of the application of the Public Service Electric and Gas Company, et al for authorization to operate the Salem Nuclear Generating Station Unit 2. This project was initially considered in connection with the review of Salem Unit 1 and at a Subcommittee meeting in Washington, D. C. on January 24, 1979. A tour of the facility was made by Committee members on January 25, 1979. During its review the Committee had the benefit of discussions with representatives and consultants of the Public Service Electric and Gas Company, the Westinghouse Electric Corporation, and the Nuclear Regulatory Commission (NRC) Staff, as well as comments from members of the public. The Committee also had the benefit of the documents listed.

The Committee reported on the application for a construction permit for the Salem Nuclear Generating Station Units 1 and 2 in its letter of June 21, 1968. The Committee reported on the application for an operating license for Unit 1 in its letter of February 14, 1975, at which time it deferred its operating license review of Unit 2 until a time somewhat closer to the expected start of operations.

In January 1978, the NRC Staff began a re-review of Salem Unit 2 to consider changes in NRC regulations or requirements, changes in the design of the plant, and operating experience with Salem Unit 1. One phase of this re-review has included current generic matters such as fire protection, industrial security, emergency planning, and ATWS. For these matters, the NRC Staff is reviewing both Units 1 and 2, and it is expected that the resolution will be substantially the same for both units.

The other phase of the re-review has addressed the degree to which Salem Unit 2 conforms to the provisions of Regulatory Guides and Branch Technical Positions that have been adopted since the operating license review was made for Salem Unit 1. These items include those classified by the

Regulatory Requirements Review Committee as Category 2 (backfit on a case-by-case basis) and as Category 3 (backfit on all plants). A comparable review of Salem Unit 1 (which initially was identical to Unit 2) is being carried out by the Division of Operating Reactors on a different time scale. The NRC Staff has stated that the reviews for Units 1 and 2 are, or will be, coordinated to provide consistency between the two units.

The NRC Staff's re-review of Salem Unit 2 is essentially complete and will be completed before an operating license is issued. There are four outstanding issues still under review or for which complete documentation has not yet been received. There are also six items for which the NRC Staff requires only confirmatory documentation regarding their resolution. The Committee believes that all of these outstanding issues and confirmatory items can and should be resolved to the satisfaction of the NRC Staff.

In its review of Salem Unit 1 and of the Hope Creek units at the same site, the Committee expressed its concern about the possibilities of accidents involving waterborne traffic on the Delaware River that might be of such a nature as to affect the safety of the plants. This question has been addressed by the NRC Staff and the Applicant on a probabilistic basis in connection with the reviews of both the Salem and Hope Creek plants. The Committee believes that the results of these studies provide a reasonable basis for assuming that the probabilities, and thus the risks, of such accidents are sufficiently low as not to provide an undue risk to the health and safety of the public. The Committee, however, continues to be concerned about accidents of this nature and believes that the potential hazards should continue to be reviewed from time to time as the local conditions may change and as the extent and reliability of the data base may be increased.

The Committee recommends that the NRC Staff establish criteria for the implementation of Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," as soon as practicable. The Committee believes that Position C.3 of this Guide should be implemented on Salem Unit 2 to the extent practicable.

With regard to the generic items cited in the Committee's report, "Status of Generic Items Relating to Light-Water Reactors: Report No. 6," dated November 15, 1977, those items considered relevant to Salem Unit 2 are: II-2, 3, 5B, 6, 7, 9, 10; IIA-2, 3, 4; IIB-2; IIC-1, 2, 3A, 3B, 4, 5, 6; IID-1, 2; IIE-1. These matters should be dealt with by the NRC Staff and the Applicant, as appropriate, when solutions are found.

The Advisory Committee on Reactor Safeguards believes that, if due regard is given to the matters mentioned above, and subject to satisfactory completion of construction and preoperational testing, there is reasonable assurance that the Salem Nuclear Generating Station Unit 2 can be operated at power levels up to 3411 Mwt without undue risk to the health and safety of the public.

Mr. J. J. Ray did not participate in the Committee's review of this project.

Sincerely,

Max W. Carbon

Max W. Carbon
Chairman

References

1. Salem Nuclear Generating Station, Units 1 and 2, Final Safety Analysis Report, with amendments 1 through 43.

2. Safety Evaluation Report, Supplement No. 3, by the Office of Nuclear Reactor Regulation, U. S. Nuclear Regulatory Commission in the matter of Public Service Electric and Gas Company, et al, Salem Nuclear Generating Station, Unit 2, NUREG-0492, dated December 29, 1978.

3. Letter to O. D. Parr, U. S. Nuclear Regulatory Commission, Light Water Reactors Branch 3, from R. L. Mittl, Public Service Electric and Gas Company, concerning additional information on single failure criteria related to pump seal for RCP, dated January 4, 1979.

4. Letter to O. D. Parr, U. S. Nuclear Regulatory Commission, Light Water Reactors Branch 3, from R. L. Mittl, Public Service Electric and Gas Company, concerning additional information on emergency action levels, dated January 8, 1979.

5. Letters from members of the Public:

   a. Letter to E. G. Igne, ACRS Staff, from Phyllis Zitzer, of the Committee for Application of Nuremberg Principles to U. S. Nuclear Power Production, dated January 18, 1979.

   b. Letter to E. G. Igne, ACRS Staff, from Joseph Blotnick, dated January 25, 1979.

   c. Letter to E. G. Igne, ACRS Staff, from Jill Higgins, of the Delaware Safe Energy Coalition, dated January 25, 1979.

d. Letter to E. G. Igne, ACRS Staff, from Nanci L. Reynolds, dated January 26, 1979.

e. Letter to E. G. Igne, ACRS Staff, from Roy Money, dated January 29, 1979.

f. Letter to E. G. Igne, ACRS Staff, from Frieda Berryhill, of Coalition for Nuclear Power Plant Postponement, dated January 30, 1979.

g. Letter to E. G. Igne, ACRS Staff, from Mary Lesser, dated February 4, 1979.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

February 22, 1979

MEMORANDUM FOR: Chairman Hendrie

FROM: R. F. Fraley, Executive Director, ACRS

SUBJECT: REVISION TO ACRS LETTER ON SALEM NUCLEAR GENERATING STATION UNIT 2 DATED FEBRUARY 15, 1979

The attached is forwarded as a replacement for Page 3 of the ACRS report on Salem Nuclear Generating Station Unit 2 dated February 15, 1979.

R. F. Fraley
Executive Director

Attachment:
Revised Page 3

The Advisory Committee on Reactor Safeguards believes that, if due regard is given to the matters mentioned above, and subject to satisfactory completion of construction and preoperational testing, there is reasonable assurance that the Salem Nuclear Generating Station Unit 2 can be operated at power levels up to 3411 Mwt without undue risk to the health and safety of the public.

Mr. J. J. Ray did not participate in the Committee's review of this project.

Sincerely,

Max W. Carbon
Max W. Carbon
Chairman

References

1. Salem Nuclear Generating Station, Units 1 and 2, Final Safety Analysis Report, with amendments 1 through 43.

2. Safety Evaluation Report, Supplement No. 3, by the Office of Nuclear Reactor Regulation, U. S. Nuclear Regulatory Commission in the matter of Public Service Electric and Gas Company, et al, Salem Nuclear Generating Station, Unit 2, NUREG-0492, dated December 29, 1978.

3. Letter to O. D. Parr, U. S. Nuclear Regulatory Commission, Light Water Reactors Branch 3, from R. L. Mittl, Public Service Electric and Gas Company, concerning additional information on single failure criteria related to pump seal for RCP, dated January 4, 1979.

4. Letter to O. D. Parr, U. S. Nuclear Regulatory Commission, Light Water Reactors Branch 3, from R. L. Mittl, Public Service Electric and Gas Company, concerning additional information on emergency action levels, dated January 8, 1979.

5. Letters from members of the Public:

   a. Letter to E. G. Igne, ACRS Staff, from Phyllis Zitzer, of the Committee for Application of Nuremberg Principles to U. S. Nuclear Power Production, dated January 18, 1979.

   b. Letter to E. G. Igne, ACRS Staff, from Joseph Blotnick, dated January 25, 1979.

   c. Letter to E. G. Igne, ACRS Staff, from Jill Higgins, of the Delaware Safe Energy Coalition, dated January 25, 1979.

APPENDIX C

NUCLEAR REGULATORY COMMISSION UNRESOLVED SAFETY ISSUES

C-1 Unresolved Safety Issues

The NRC staff continuously evaluates the safety requirements used in its reviews against new information as it becomes available. Information related to the safety of nuclear power plants comes from a variety of sources including experience from operating reactors, research results, NRC staff and Advisory Committee on Reactor Safeguards safety reviews, and vendor, architect/engineer and utility design reviews. Each time a new concern or safety issue is identified from one or more of these sources, the need for immediate action to assure safe operation is assessed. This assessment includes consideration of the generic implications of the issue.

In some cases, immediate action is taken to assure safety, e.g., the derating of boiling water reactors as a result of the channel box wear problems in 1975. In other cases, interim measures, such as modifications to operating procedures, may be sufficient to allow further study of the issue prior to making licensing decisions. In most cases, however, the initial assessment indicates that immediate licensing actions or changes in licensing criteria are not necessary. In any event, further study may be deemed appropriate to make judgments as to whether existing NRC staff requirements should be modified to address the issue for new plants or if backfitting is appropriate for the long-term operation of plants already under construction or in operation.

These issues are sometimes called "generic safety issues" because they are related to a particular class or type of nuclear facility rather than a specific plant. These issues have also been referred to as "unresolved safety issues." However, as discussed above, such issues are considered on a generic basis only after the staff has made an initial determination that the safety significance of the issue does not prohibit continued operation or require licensing actions while the longer-term generic review is underway.

C-2 ALAB-444 Requirements

These longer-term generic studies were the subject of a Decision by the Atomic Safety and Licensing Appeal Board of the Nuclear Regulatory Commission. The Decision was issued on November 23, 1977 (ALAB-444) in connection with the Appeal Board's consideration of the Gulf States Utility Company application for the River Bend Station, Unit Nos. 1 and 2.

In the view of the Appeal Board (pp. 25-29):

"The responsibilities of a licensing board in the radiological health and safety sphere are not confined to the consideration and disposition of those issues which may have been presented to it by a party or an "Interested State" with the required degree of specificity. To the contrary, irrespective of what matters may or may not have been properly placed in controversy, prior to authorizing the issuance of a construction permit the board must make the finding, <u>inter alia</u>, that there is "reasonable assurance" that "the proposed facility can be constructed and operated at the proposed location without undue risk to the health and safety of the public." 10 CFR 50.35(a)...Of necessity, this determination will entail an inquiry into whether the staff review satisfactorily has come to grips with any unresolved generic safety problems which might have an impact upon operation of the nuclear facility under consideration."

"The SER is, of course, the principal document before the licensing board which reflects the content and outcome of the staff's safety review. The board should therefore be able to look to that document to ascertain the extent to which generic unresolved safety problems which have been previously identified in a TSAR item, a Task Action Plan, an ACRS report or elsewhere have been factored into the staff's analysis for the particular reactor -- and with what result. To this end, in our view, each SER should contain a summary description of those generic problems under continuing study which have both relevance to facilities of the type under review and potentially significant public safety implications."

"This summary description should include information of the kind now contained in most Task Action Plans. More specifically, there should be an indication of the investigative program which has been or will be undertaken with regard to the problem, the program's anticipated timespan, whether (and if so, what) interim measures have been devised for dealing with the problem pending the completion of the investigation, and what alternative courses of action might be available should the program not produce the envisaged result."

"In short, the board (and the public as well) should be in a position to ascertain from the SER itself -- without the need to resort to extrinsic documents -- the staff's perception of the nature and extent of the relationship between each significant unresolved generic safety question and the eventual operation of the reactor under scrutiny. Once again, this assessment might well have a direct bearing upon the ability of the licensing board to make the safety findings required of it on the construction permit level even though the generic answer to the question remains in the offing. Among other things, the furnished information would likely shed light on such alternatively important considerations as whether: (1) the problem has already been resolved for the reactor under study; (2) there is a reasonable basis for concluding that a satisfactory solution will be obtained before the reactor is put in operation; or (3) the problem would have no safety implications until after several years of reactor operation and, should it not be resolved by then, alternative means will be available to insure that continued operation (if permitted at all) would not pose an undue risk to the public."

This appendix is specifically included to respond to the decision of the Atomic Safety and Licensing Appeal Board as enunciated in ALAB-444.

C-3 "Unresolved Safety Issues"

In a related matter, as a result of Congressional action on the Nuclear Regulatory Commission budget for Fiscal Year 1978, the Energy Reorganization Act of 1974 was amended (PL 95-209) on December 13, 1977 to include, among other things, a new Section 210 as follows:

"UNRESOLVED SAFETY ISSUES PLAN"

"SEC. 210. The Commission shall develop a plan providing for specification and analysis of unresolved safety issues relating to nuclear reactors and shall take such action as may be necessary to implement corrective measures with respect to such issues. Such plan shall be submitted to the Congress on or before January 1, 1978 and progress reports shall be included in the annual report of the Commission thereafter."

The joint Explanatory Statement of the House-Senate Conference Committee for the FY 1978 Appropriations Bill (Bill S.1131) provided the following additional information regarding the Committee's deliberations on this portion of the bill:

"SECTION 3 - UNRESOLVED SAFETY ISSUES"

"The House amendment required development of a plan to resolve generic safety issues. The conferees agreed to a requirement that the plan be submitted to the Congress on or before January 1, 1978. The conferees also expressed the intent that this plan should identify and describe those safety issues, relating to nuclear power reactors, which are unresolved on the date of enactment. It should set forth: (1) Commission actions taken directly or indirectly to develop and implement corrective measures; (2) further actions planned concerning such measures; and (3) timetables and cost estimates of such actions. The Commission should indicate the priority it has assigned to each issue, and the basis on which priorities have been assigned."

In response to the reporting requirements of the new Section 210, the NRC staff submitted to Congress on January 1, 1978, a report describing the NRC generic issues program (NUREG-0410).[1/] The NRC program was already in place when PL 95-209

[1/] NUREG-0410, "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants," issued on January 1, 1978.

was enacted and is of considerably broader scope than the "Unresolved Safety Issues Plan" required by Section 210. In the letter transmitting NUREG-0410 to the Congress on December 30, 1977, the Commission indicated that "the progress reports, which are required by Section 210 to be included in future NRC annual reports, may be more useful to Congress if they focus on the specific Section 210 safety items."

It is the NRC's view that the intent of Section 210 was to assure that plans were developed and implemented on issues with potentially significant public safety implications. In 1978, the NRC undertook a review of over 130 generic issues addressed in the NRC program to determine which issues fit this description and qualify as "Unresolved Safety Issues" for reporting to the Congress. The NRC review included the development of proposals by the NRC staff and review and final approval by the NRC Commissioners.

This review is described in a report, NUREG-0510, entitled "Identification of Unresolved Safety Issues Relating to Nuclear Power Plants - A Report to Congress" dated January 1979. The report provides the following definition of an "Unresolved Safety Issue":

> "An Unresolved Safety Issue is a matter affecting a number of nuclear power plants that poses important questions concerning the adequacy of existing safety requirements for which a final resolution has not yet been developed and that involves conditions not likely to be acceptable over the lifetime of the plants it affects."

Further the report indicates that in applying this definition, matters that pose "important questions concerning the adequacy of existing safety requirements" were judged to be those for which resolution is necessary to (1) compensate for a possible major reduction in the degree of protection of the public health and safety, or (2) provide a potentially significant decrease in the risk to the public health and safety. Quite simply, an "Unresolved Safety Issue" is potentially significant from a public safety standpoint and its resolution is likely to result in NRC action on the affected plants.

All of the issues addressed in the NRC program were systematically evaluated against this definition as described in NUREG-0510. As a result, 17 "Unresolved Safety Issues" addressed by 22 tasks in the NRC program were identified. The issues are listed below. Progress on these issues was discussed in the 1978 NRC Annual Report. The number(s) of the generic task(s) (e.g., A-1) in the NRC program addressing each issue is indicated in parentheses following the title.

"UNRESOLVED SAFETY ISSUES" (APPLICABLE TASK NOS.)

1. Water Hammer - (A-1)
2. Asymmetric Blowdown Loads on the Reactor Coolant System - (A-2)
3. Pressurized Water Reactor Steam Generator Tube Integrity - (A-3, A-4, A-5)
4. BWR Mark I and Mark II Pressure Suppression Containments - (A-6, A-7, A-8, A-39)
5. Anticipated Transients Without Scram - (A-9)
6. BWR Nozzle Cracking - (A-10)
7. Reactor Vessel Materials Toughness - (A-11)
8. Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports - (A-12)
9. Systems Interaction in Nuclear Power Plants - (A-17)
10. Environmental Qualification of Safety-Related Electrical Equipment - (A-24)
11. Reactor Vessel Pressure Transient Protection - (A-26)
12. Residual Heat Removal Requirements - (A-31)
13. Control of Heavy Loads Near Spent Fuel - (A-36)
14. Seismic Design Criteria - (A-40)
15. Pipe Cracks at Boiling Water Reactors - (A-42)
16. Containment Emergency Sump Reliability - (A-43)
17. Station Blackout - (A-44)

In the view of the staff, the "Unresolved Safety Issues" listed above are the substantive safety issues referred to by the Appeal Board in ALAB-444 when it spoke of "...those generic problems under continuing study which have...potentially significant public safety implications" (page 27). Eight of the 22 tasks identified with the above 17 "Unresolved Safety Issues" are not applicable to Salem Unit 2. Six of these tasks (A-6, A-7, A-8, A-39, A-10 and A-42) are peculiar to boiling water reactors and two of the tasks (A-4 and A-5) are peculiar to pressurized water reactors with Babcock & Wilcox and Combustion Engineering nuclear steam supply systems.[2/] With regard to the other 14 tasks that are applicable to Salem Unit 2, the NRC staff has issued NUREG reports and other documents providing its proposed resolution of four of the issues as listed below.

[2/] Even though Tasks A-4 and A-5 address steam generator tube problems experienced in CE and B&W plants, there are many common task elements between these tasks and Task A-3 which addresses Westinghouse steam generator tube problems. For this reason, the Task Action Plans for all three tasks have been combined into a single Task Action Plan.

Task Number	NUREG Report and Title	Safety Evaluation Report/ Safety Evaluation Report Supplement Section
A-12	NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports"	Section 3.9.4 of Supplement Nos. 2 and 3
A-24	NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment"	Section 3.11 of Supplement No. 3 and of this supplement
A-26	NUREG-0224, "Reactor Vessel Pressure Transient Protection for Pressurized Water Reactors"	Section 5.2.3 of Supplement No. 3
	Branch Technical Position RSB 5-2, "Reactor Coolant System Overpressurization Protection"	
A-31	Regulatory Guide 1.139, "Guidance for Residual Heat Removal"	Section 5.7 of Supplement No. 3
	Branch Technical Position RSB 5-1, "Design Requirements of the Residual Heat Removal Systems"	

The remaining 10 tasks that are applicable to Salem Unit 2 are listed below.

GENERIC TASKS ADDRESSING UNRESOLVED SAFETY ISSUES THAT ARE APPLICABLE TO SALEM UNIT 2

1. A-1 Water Hammer
2. A-2 Asymmetric Blowdown Loads on PWR Primary Systems
3. A-3 Westinghouse Steam Generator Tube Integrity
4. A-9 ATWS
5. A-11 Reactor Vessel Materials Toughness
6. A-17 Systems Interaction in Nuclear Power Plants
7. A-36 Heavy Loads Near Spent Fuel
8. A-40 Seismic Design Criteria
9. A-43 Containment Emergency Sump Reliability
10. A-44 Station Blackout

With the exception of Tasks A-9, A-43 and A-44, the Task Action Plans for the generic tasks above are included in NUREG-0649, "Task Action Plans for Unresolved Safety Issues Related to Nuclear Power Plants." The Task Action Plan for Task A-9 is currently being revised. Task Action Plans for Tasks A-43 and A-44 are currently under development. The information provided in NUREG-0649 meets most of the informational requirements of ALAB-444. Each Task Action Plan provides a description of the problem; the staff's approaches to its resolution; a general discussion of the bases upon which continued plant licensing or operation can proceed pending completion of the task; the technical organizations involved in the task and estimates of the manpower required; a description of the interactions with other NRC offices, the Advisory Committee on Reactor Safeguards and outside organizations; estimates of funding required for contractor supplied technical assistance; prospective dates for completing the task; and a description of potential problems that could alter the planned approach or schedule.

We have reviewed the 10 "Unresolved Safety Issues" listed above as they relate to Salem Unit 2. Discussion of each of these issues including references to related discussions in the Safety Evaluation Report and its supplements are provided below in Section C-5. Based on our review of these items, we have concluded, for the reasons set forth in Section C-5, that there is reasonable assurance that Salem Unit 2 can be operated prior to the ultimate resolution of these generic issues without endangering the health and safety of the public.

C-4 New "Unresolved Safety Issues"

No new issues have been identified in 1979 for reporting as "Unresolved Safety Issues." However, the NRC staff has not been able to perform an in-depth review to identify and evaluate new issues. NRC efforts have been concentrated on implementing new TMI-related requirements on operating plants and on identifying, defining, and scoping additional TMI-related issues and tasks. Several broad program areas where issues and tasks are being scoped will likely result in designation of new "Unresolved Safety Issues." These program areas include the following:

1. Man-machine interface and control-room design.

2. Qualification and training of operation, maintenance, and supervisory personnel.

3. Offsite emergency response, emergency planning, and action guidelines.

4. Siting policy, including compensatory design and operating provisions for plants in areas where evacuation would be difficult.

5. Systems reliability and interactions.

6. Consideration in licensing requirements of accidents involving degraded or melted fuel.

Nonetheless, the specific TMI-related requirements for licensing Salem Unit 2 have been identified and are discussed in Part 2 of this supplement. Many of these are related to the program areas listed above. Long-term "Unresolved Safety Issue" tasks that may be undertaken in the same program areas could provide a basis for further improvements that may or may not be applicable to Salem Unit 2.

The NRC staff also performed a cursory review of a number of candidate issues from sources other than Three Mile Island accident investigations, including a review of events reported as Abnormal Occurrences in 1979. Based on this cursory review, none were judged to be of such safety importance to require reporting to the Congress in the 1979 Annual Report as "Unresolved Safety Issues." An in-depth and systematic review of all candidate issues will be performed by the staff and the Commission in the first half of 1980. A special report will be provided to the Congress by July 1, 1980, describing the review and new issues designated as "Unresolved Safety Issues." Their applicability to all plants will be determined at that time.

C-5 Discussion of Tasks as they Relate to Salem Unit 2

A-1 Water Hammer

Water hammer events are intense pressure pulses in fluid systems caused by any one of a number of mechanisms and system conditions. Since 1971 there have been over 100 incidents involving water hammer in pressurized water reactors and boiling water reactors. The water hammers have involved steam generator feedrings and piping, decay heat removal systems, emergency core cooling systems, containment spray lines, service water lines, feedwater lines and steam lines. However, the systems most frequently affected by water hammer effects are the feedwater systems. The most serious water hammer events have occurred in the steam generator feedrings of pressurized water reactors.

These latter types of water hammer events are addressed in Section 10.3 of Supplement No. 1 to the Safety Evaluation Report. For Salem Unit 2, feedwater system modifications have been made and testing of the systems will be performed as part of the plant startup program to demonstrate that a steam generator feedring water hammer will not occur. These provisions are discussed in Section 10.3 of Supplement No. 1 and Section 10.4 of Supplement No. 3 to the Safety Evaluation Report where the staff found these provisions to be acceptable.

With regard to protection against other potential water hammer events currently provided in plants, piping design codes require consideration of impact loads. Approaches used at the design stage include: (1) increasing valve closure times, (2) piping layout to preclude water slugs in steam lines and vapor formation in water lines, (3) use of snubbers and pipe hangers, and (4) use of vents and drains. In addition, as described in Section 3.9.1 of the Safety Evaluation Report, we require that the applicants conduct a preoperational vibration dynamic effects test program for all ASME Class 1, 2 and 3 piping systems and piping restraints during startup and initial operation. These tests will provide adequate assurance that the piping and piping restraints have been designed to withstand dynamic effects due to valve closures, pump trips, and other operating modes associated with the design operational transients.

Nonetheless, in the unlikely event that a large piping break did result from a severe water hammer event, core cooling is assured by the emergency core cooling systems described in Section 6.3 of the Safety Evaluation Report and its supplements, and protection against the dynamic effects of such pipe breaks inside and outside of containment is provided as described in Sections 3.6.1 and 3.6.2 of the Safety Evaluation Report and Sections 3.6.2 and 3.6.3 of Supplement No. 3 to the Safety Evaluation Report.

Task A-1 may identify some potentially significant water hammer scenarios that have not explicitly been accounted for in the design and operation of nuclear power plants, including Salem Unit 2. The task has not as yet identified the need for requiring any additional measures beyond those already required in the short term.

Based on the foregoing, we have concluded that Salem Unit 2 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-2 Asymmetric Blowdown Loads on Primary Coolant Systems

In the very unlikely event of a rupture of the primary coolant piping in light water reactors, large nonuniformly distributed loads would be imposed upon the reactor vessel, reactor vessel internals, and other components in the reactor coolant system. The potential for such asymmetric loads, which result from the rapid depressurization of the reactor coolant system, was only recently identified and was not considered in the original design of some facilities. The forces associated with a postulated break in the reactor coolant piping near the reactor vessel, for example, could affect the integrity of the reactor vessel supports and reactor pressure vessel internals. A significant failure of the reactor vessel support system, besides impacting the reactor internals, has a potential for (1) damaging systems designed to cool the core following the postulated piping break, (2) affecting the capability of the control rods to function properly, (3) damaging other reactor coolant system components, and (4) causing other ruptures in the initially unbroken reactor coolant system piping loops and attached systems.

As indicated in Section 3 of the Task Action Plan for Task A-2 in NUREG-0649, we currently require that this issue be resolved prior to issuing an operating license. This issue has been acceptably resolved for the Salem Unit 2. Our evaluation of and conclusions for this matter are provided in Sections 3.9.1 and 6.2.1 of this supplement. Accordingly, we have concluded that Salem Unit 2 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-3 Westinghouse Steam Generator Tube Integrity

The primary concern is the capability of steam generator tubes to maintain their integrity during normal operation and postulated accident conditions. In addition, the requirements for increased steam generator tube inspections and repairs have resulted in significant increases in occupational exposures to workers. Corrosion resulting in steam generator tube wall thinning has been observed in several Westinghouse and Combustion Engineering plants for a number of years. Major changes in their secondary water treatment process essentially eliminated this form of degradation. Another major corrosion-related phenomenon has also been observed in a number of plants in recent years, resulting from a buildup of support plate corrosion products in the annulus between the tubes and the support plates. This buildup eventually causes a diametral reduction of the tubes, called "denting," and deformation of the tube support plates. This phenomenon has led to other problems, including stress corrosion cracking, leaks at the tube/support plate intersections, and U-bend section cracking of tubes which were highly stressed because of support plate deformation.

Specific measures, such as a secondary water chemistry control and monitoring program, that the applicants will employ to minimize the onset of steam generator tube problems are described in Section 5.2.5 of Supplement No. 1 to the Safety Evaluation Report and this supplement. In addition, Section 5.3 of Supplement No. 3 discusses the inservice inspection requirements for steam generator tubes. As described in these sections, the applicants have met all current requirements regarding steam generator tube integrity. The Technical Specifications will include requirements for actions to be taken in the event that steam generator tube leakage occurs during plant operation.

Task A-3 is expected to result in improvements in our current requirements for inservice inspection of steam generator tubes. These improvements will include a better statistical basis for inservice inspection program requirements and consideration of the cost/benefit of increased inspection. Pending completion of Task A-3, the measures taken at Salem Unit 2 should minimize the steam generator tube problems encountered. Further, the inservice inspection and Technical Specification requirements will assure that the applicants and the NRC staff are alerted to tube degradation should it occur. Appropriate actions such as tube plugging, increased and more frequent inspections and power derating could be taken if necessary. Since the improvements that will result from Task A-3 will be procedural, i.e., an improved inservice inspection program, they can be implemented by the applicants at Salem Unit 2 after operation begins, if necessary.

Based on the foregoing, we have concluded that Salem Unit 2 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-9 Anticipated Transients Without Scram (ATWS)

Nuclear plants have safety and control systems to limit the consequences of temporary abnormal operating conditions or "anticipated transients." Some deviations from normal operating conditions may be minor; others, occurring less frequently, may impose significant demands on plant equipment. In some anticipated transients, rapidly shutting down the nuclear reaction (initiating a "scram"), and thus rapidly reducing the generation of heat in the reactor core, is an important safety measure. If there were a potentially severe "anticipated transient" and the reactor shutdown system did not "scram" as desired, then an "anticipated transient without scram," or ATWS, would have occurred.

The ATWS issue and the requirements that must be met by the applicants prior to operation of Salem Unit 2 are discussed in Section 7.2.2 of this supplement. The requirements set forth are for the interim period pending completion of Task A-9 and implementation of additional requirements if found to be necessary.

The applicants have submitted some proposed ATWS procedures, which are being reviewed and commented on by the staff. The proposed procedures are not fully acceptable for full power operation, and require modification by the applicants. However, we have concluded that the plant may be safely operated at low power prior to completion of this effort, and that the applicants can prepare adequate ATWS procedures, in accordance with our guidance, prior to full power operation.

Accordingly, we have concluded that Salem Unit 2 can be operated safely prior to the ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-11 Reactor Vessel Materials Toughness

Resistance to brittle fracture, a rapidly propagating catastrophic failure mode for a component containing flaws, is described quantitatively by a material property generally denoted as "fracture toughness." Fracture toughness has different values and characteristics depending upon the material being considered. For steels used in nuclear reactor pressure vessels, three considerations are important. First, fracture toughness increases with increasing temperature. Second, fracture toughness decreases with increasing load rates. Third, fracture toughness decreases with neutron irradiation.

In recognition of these considerations, power reactors are operated within restrictions imposed by the Technical Specifications on the pressure during heatup and cooldown operations. These restrictions assure that the reactor vessel will not be subjected to that combination of pressure and temperature that could cause brittle fracture of the vessel if there were significant flaws in the vessel material. The effect of neutron radiation on the fracture toughness of the vessel material is accounted for in developing and revising these Technical Specification limitations over the life of the plant.

For the service times and operating conditions typical of current operating plants, reactor vessel fracture toughness for most plants provides adequate margins of safety against vessel failure under operating, testing, maintenance, and anticipated transient conditions over the life of the plant. In addition, conservative analyses indicate that adequate safety margins are available during accident conditions until after many years of operation. However, results from a reactor vessel surveillance program and analyses performed using currently available methods indicate that the reactor vessels for up to 20 older operating pressurized water reactors and those for some more recent vintage plants will have marginal toughness after comparatively short periods of operation. The principal objective of Task A-11 is to develop an improved engineering method and safety criteria to allow a more precise assessment of the safety margins that are available during normal operation and transients in older reactor vessels with marginal fracture toughness and of the safety margins available during accident conditions for all plants.

Our evaluation of the reactor vessel materials fracture toughness and reactor vessel integrity requirements of Appendix G to 10 CFR Part 50 for Salem Unit 2 during normal operation, testing, maintenance, and anticipated transient conditions is described in Section 5.2.1 of this supplement and Supplement No. 3 to the Safety Evaluation Report. In Section 5.2.1 of this supplement, we indicated that the applicants meet the fracture toughness requirements of Appendix G to 10 CFR Part 50.

Results from analyses performed by pressurized water reactor manufacturers indicate that the integrity of some reactor vessels may not be maintained in the event that a main steam line break or a loss-of-coolant accident occurs after approximately 20 years of operation. For most plants now undergoing licensing review, materials currently used for vessel fabrication will likely maintain acceptable fracture resistance over the design life of the plant. However, some pressurized water reactors in the later stages of licensing have the potential after many years of operation to have marginal fracture toughness for these postulated accident conditions. When Task A-11 is completed and explicit fracture evaluation criteria for accident conditions are defined, all vessels will be reevaluated for acceptability over their design lives. Since Task A-11 is projected to be completed many years before the Salem Unit 2 vessel could have marginal fracture resistance for postulated accident conditions, acceptable vessel integrity will be assured until the vessel is reevaluated for long term acceptability.

Based on the foregoing, we have concluded that Salem Unit 2 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-17 Systems Interaction in Nuclear Power Plants

The licensing requirements and procedures used in our safety review address many different types of systems interactions. Current licensing requirements are founded on the principle of defense-in-depth. Adherence to this principle results in requirements such as physical separation and independence of redundant safety systems, and protection against events such as high energy line ruptures, missiles, high winds, flooding, seismic events, fires, operator errors, and sabotage. These design provisions supplemented by the current review procedures of the Standard Review Plan (NUREG-75/087) which require interdisciplinary reviews and which account, to a large extent, for review of potential systems interactions, provide for an adequately safe situation with respect to such interactions. The quality assurance program which is followed during the design, construction, and operational phases for each plant is expected to provide added assurance against the potential for adverse systems interactions.

In November 1974, the Advisory Committee on Reactor Safeguards requested that the NRC staff give attention to the evaluation of safety systems from a multidisciplinary point of view, in order to identify potentially undesirable interactions between plant systems. The concern arises because the design and analysis of systems is frequently assigned to teams with functional engineering specialties--such as civil, electrical, mechanical, or nuclear. The question is whether the work of these functional specialists is sufficiently integrated in their design and analysis activities to enable them to identify adverse interactions between and among systems. Such adverse events might occur, for example, because designers did not assure that redundancy and independence of safety systems were provided under all conditions of operation required, which might happen if the functional teams were not adequately coordinated. Simply stated, the left hand may not know or understand what the right hand is doing in all cases where it is necessary for the hands to be coordinated.

In mid-1977, Task A-17 was initiated to confirm that present review procedures and safety criteria provide an acceptable level of redundancy and independence for systems required for safety by evaluating the potential for undesirable interactions between and among systems.

The NRC staff's current review procedures assign primary responsibility for review of various technical areas and safety systems to specific organizational units and assign secondary responsibility to other units where there is a functional or interdisciplinary relationship. Designers follow somewhat similar procedures and provide for interdisciplinary reviews and analyses of systems. Task A-17 will provide an independent investigation of safety functions--and systems required to perform these functions--in order to assess the adequacy of current review procedures. This investigation is being conducted by Sandia Laboratories under contract assistance to the NRC staff.

The contract effort, Phase I of the task, began in May 1978 and is nearing completion. The Phase I investigation is structured to identify areas where interactions are possible between and among systems and have the potential of negating or seriously degrading the performance of safety functions. The investigation will then identify where NRC review procedures may not have properly accounted for these interactions. Preliminary results of the Phase I contracted effort indicate that, within the limitations of the study, there are only a few areas where the review procedures are weak from a systems interaction standpoint. These results are being finalized by the contractor and the staff is considering whether, and if so what changes in the Standard Review Plan are needed. Finally, a follow-on Phase II of the task will be scoped based on the results of Phase I and the status and scope of other related NRC activities.

The NRC staff believes that its review procedures and acceptance criteria currently provide reasonable assurance that an acceptable level of system redundancy and independence is provided in plant designs. Although some changes to the review procedures will likely result, the preliminary results of the Phase I effort appear to confirm this belief. Therefore, we conclude that there is reasonable assurance that Salem Unit 2 can be operated prior to the ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-36 Control of Heavy Loads Near Spent Fuel

Overhead cranes are used to lift heavy objects, sometimes in the vicinity of spent fuel, in both pressurized and boiling water reactors. If a heavy object, such as a spent fuel shipping cask or shielding block, were to fall or tip onto spent fuel in the storage pool or in the reactor core during refueling and damage the fuel, there could be a release of radioactivity to the environment and a potential for radiation overexposures to in-plant personnel. If the dropped object is large, and is assumed to drop on fuel containing a large amount of fission products with minimal decay time, calculated offsite doses could exceed the siting guideline values in 10 CFR Part 100.

The applicants have complied with our requirements for the safe handling of fuel and spent fuel casks as discussed in Appendix D to this supplement. In addition, the Technical Specifications will include a prohibition on the movement of loads over spent fuel in the storage pool that weigh more than the equivalent weight of a fuel assembly. These measures provide reasonable assurance that the likelihood of a load handling accident damaging enough spent fuel to cause unacceptable consequences is small for Salem Unit 2.

Task A-36 may result in additional requirements applicable to Salem Unit 2 to further reduce the likelihood of such accidents. These additional requirements are expected to be procedural and therefore can be implemented at Salem Unit 2 after operation begins if found to be desirable.

In the interim period, the current design, administrative and procedural measures are acceptable as indicated above. Accordingly, we have concluded that there is reasonable assurance that Salem Unit 2 can be operated prior to the ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-40 Seismic Design Criteria - Short-Term Program

NRC regulations require that nuclear power plant structures, systems and components important to safety be designed to withstand the effects of natural phenomena such as earthquakes. Detailed requirements and guidance regarding the seismic design of nuclear plants are provided in the NRC regulations and in regulatory guides issued by the NRC staff. However, there are a number of plants with construction permits and operating licenses issued before the NRC's current regulations and regulatory guidance were in place. For this reason, rereviews of the seismic design of various plants are being undertaken to assure that these plants do not present an undue risk to the public.

Task A-40 is, in effect, a compendium of short-term efforts to support such reevaluation efforts of the NRC staff, especially those related to older operating plants. In addition, some revisions to Standard Review Plan sections and regulatory guides to bring them more in line with the state-of-the-art will result.

As discussed in Sections 3.7 and 3.8 of the Safety Evaluation Report and its supplements, the seismic design bases and seismic design of Salem Unit 2 have been reevaluated at the operating license stage and have been found acceptable. The results of Task A-40 will not affect these conclusions. Accordingly, we have concluded that Salem Unit 2 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-43 Containment Emergency Sump Reliability

Following a postulated loss-of-coolant accident, i.e., a break in the reactor coolant system piping, the water flowing from the break would be collected in the emergency sump at the low point in the containment. This water would be recirculated through the reactor system by the emergency core cooling pumps to maintain core cooling. This water would also be circulated through the containment spray system to remove heat and fission products from the containment. Loss of the ability to draw water from the emergency sump could disable the emergency core cooling and containment spray systems. The consequences of the resulting inability to cool the reactor core or the containment atmosphere could be melting of the core and/or loss of containment integrity.

One postulated means of losing the ability to draw water from the emergency sump could be blockage by debris. A principal source of such debris could be the thermal insulation on the reactor coolant system piping. In the event of a piping break, the subsequent violent release of the high pressure water in the reactor coolant system could rip off the insulation in the area of the break. This debris could then be swept into the sump, potentially causing blockage.

Currently, regulatory positions regarding sump design are presented in Regulatory Guide 1.82, "Sumps for Emergency Core Cooling and Containment Spray Systems," which addresses debris (insulation). The regulatory guide recommends, in addition to providing redundant separated sumps, that two protective screens be provided. A low approach velocity in the vicinity of the sump is needed to allow insulation to settle out before reaching the sump screening; and the sump should remain functional assuming that one-half of the screen surface area is blocked.

A second postulated means of losing the ability to draw water from the emergency sump could be abnormal conditions in the sump or at the pump inlet such as air entrainment, vortices, or excessive pressure drops. These conditions could result in pump cavitation, reduced flow and possible damage to the pumps.

Currently, regulatory positions regarding sump testing are contained in Regulatory Guide 1.79, "Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors," which addresses the testing of the recirculation function. In-plant tests for Salem Unit 1 have been performed by the applicants to demonstrate that circulation through the sump can be reliably accomplished. As indicated in Section 6.3.3 of this supplement, the applicants will also perform out-of-plant scale model tests of the Salem Unit 2 containment sump design. We will review the model test results to assure that circulation through the sump can be reliably accomplished.

Task A-43 is principally concerned with the adequacy of emergency sump performance for plants licensed to operate before current design and testing requirements were imposed. The results of Task A-43 are not expected to alter our conclusions for the Salem Unit 2 sump.

Accordingly, we have concluded that Salem Unit 2 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-44 Station Blackout

Electrical power for safety systems at nuclear power plants must be supplied by at least two redundant and independent divisions. The systems used to remove decay heat to cool the reactor core following a reactor shutdown are included among the safety systems that must meet these requirements. Each electrical division for safety systems includes an offsite alternating current (ac) power connection, a standby emergency diesel generator ac power supply, and direct current (dc) sources.

Task A-44 involves a study of whether or not nuclear power plants should be designed to accommodate a complete loss of all ac power, i.e., a loss of both the offsite and the emergency diesel generator ac power supplies. A loss of all ac power for an extended period of time in pressurized water reactors accompanied by loss of the auxiliary feedwater pumps (usually one of two redundant pumps is a steam turbine driven pump that is not dependent on ac power for actuation or operation) could result in an inability to cool the reactor core, with potentially serious consequences. This particular accident sequence was a significant contributor to the overall risk associated with the pressurized water reactor analyzed in the Reactor Safety Study (WASH-1400). The steam turbine driven auxiliary feedwater pump for the pressurized water reactor analyzed in WASH-1400 had no ac power dependencies. If the auxiliary feedwater pumps are dependent on ac power to function, then a loss of all ac power could of itself result in an inability to cool the reactor core and, accordingly, this event sequence would be expected to be more important to the overall risk posed by the facility.

A loss of all ac power was not a design basis event for Salem Unit 2. Nonetheless, the combination of design, operation, and testing requirements that have been imposed on the applicants will assure that this unit will have substantial resistance to a loss of all ac power and that even if a loss of all ac power should occur, there is reasonable assurance that the core will be cooled. These are discussed below.

A loss of offsite ac power involves a loss of both the preferred and backup sources of offsite power. Our review and basis for acceptance of the design, inspection, and testing provisions for the offsite power system are described in Section 8.2 of the Safety Evaluation Report and its supplements. In addition, the applicants conducted a grid stability analysis. Our review of this analysis is described in Section 8.2 of this supplement and in Supplement No. 3 to the Safety Evaluation Report.

If offsite ac power is lost, three independent and redundant onsite diesel generators and their associated distribution systems will deliver emergency power to safety- related equipment. Our review of the design, testing, surveillance, and maintenance provisions for Salem Unit 2 onsite emergency diesels is described in Section 8.3 of the Safety Evaluation Report, Supplement No. 3 and this supplement. Our requirements include preoperational testing to assure the reliability of the installed diesel generators in accordance with the provisions of Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants." In addition, as discussed in Section 8.3.4 of this supplement, the applicants have been requested to implement a program for enhancement of diesel generator reliability to better assure the long-term reliability of the diesel generators.

Even if both offsite and onsite ac power are lost, cooling water can still be provided to the steam generators by the auxiliary feedwater system by employing a steam turbine driven pump that does not rely on ac power for operation. Our review of the auxiliary feedwater system design and operation is described in Section 10.4 of the Safety Evaluation Report. Our review of the operation of the steam turbine driven auxiliary feedwater pump, without reliance on ac power, is presented in NUREG-0611, "Generic Evaluation of Feedwater Transients and Small Break Loss of Coolant Accidents in Westinghouse - Designed Operating Plants." Additional actions by the NRC staff and the applicants to improve the reliability of the auxiliary feedwater systems for Salem Unit 2 are described in Part II of this supplement in Section II.K.3.

In addition, we are requiring the applicants to perform analyses of accidents and transients and to develop operating guidelines, operating procedures, and conduct operator training based on these analyses as described in Part II of this supplement in Section I.C.1. These requirements will include consideration of loss of all ac power. With regard to testing, the applicants have included a simulated loss of all ac power in its low power test program as described in Section I.G.

Based on the foregoing, we have concluded that there is reasonable assurance that Salem Unit 2 can be operated prior to the ultimate resolution of this generic issue without undue risk to the health and safety of the public.

APPENDIX D

SAFETY EVALUATION BY THE OFFICE OF

NUCLEAR REACTOR REGULATION

RELATING TO THE MODIFICATION OF THE

SPENT FUEL STORAGE POOL

FACILITY OPERATING LICENSE NO. DPR-70

PUBLIC SERVICE ELECTRIC & GAS COMPANY

SALEM NUCLEAR GENERATING STATION UNIT NO. 1

DOCKET NO. 50-272

1.0 INTRODUCTION

By letter dated November 18, 1977, as revised on February 14, 1978, and as supplemented on December 13, 1977, May 17, July 31, August 22, October 13 and 31, November 20 and December 22, 1978, and January 4, 1979, Public Service Electric & Gas Company, et al. (PSE&G) requested an amendment to facility Operating License No. DPR-70 for the Salem Nuclear Generating Station, Unit No. 1. The request was made to obtain authorization to provide additional storage capacity in the Salem Unit No. 1 Spent Fuel Pool (SFP). By letter dated April 12, 1978, the licensee submitted Amendment No. 42 to the Application for Licenses for the construction and operation of the Salem Nuclear Generating Station, Units No. 1 and 2, consisting of changes to the Final Safety Analysis Report including a revised description of the spent fuel storage facilities for both units to reflect the proposed design changes of the Unit No. 1 license amendment application. The proposed modifications would increase the capacity of each SFP from the present design capacity of 264 fuel assemblies to a capacity of 1170 fuel assemblies.

The increased SFP capacity would be achieved by installing new racks with a decreased spacing between fuel storage cavities. The present rack design has a nominal center-to-center spacing between fuel storage cavities of 21 inches. The proposed new spent fuel racks would be modular stainless steel structures with individual storage cavities to provide a nominal center-to-center spacing of 10.5 inches. Each stainless steel wall of the individual cavities would contain sheets of Boral (Boron Carbide in an aluminum matrix) to provide for neutron absorption. The SFPs are located in separate fuel handling buildings adjacent to the respective reactor containment buildings. The general arrangement and details of the proposed new spent fuel storage racks are shown in Figures 1.2-1 through 1.2-4 of the licensee's revised submittal of February 14, 1978.

The expanded storage capacity of the Unit No. 1 SFP would allow Unit No. 1 to operate until about 1996, or until about 1993 while still maintaining the capability for a full core discharge.

The major safety considerations associated with the proposed expansion of the SFP storage capacity for Salem Unit 1 are addressed below. A separate environmental impact appraisal has been prepared for this proposed action.

2.0 DISCUSSION AND EVALUATION

2.1 Criticality Considerations

The proposed spent fuel storage racks will be an assemblage of open-ended double-walled stainless steel boxes with storage space for one fuel assembly in the cavity of each box. These boxes will be about 14 feet long and will have a square cross section with an inner dimension of 8.97 inches. The nominal distance between the centers of the stored fuel assemblies, i.e., the lattice pitch, will be 10.5 inches. The effective side dimension of the square fuel assembly, which was used in the criticality calculations, is 8.432 inches. This results in an overall fuel region volume fraction of 0.645 in the nominal storage lattice cell. Boral (boron carbide and aluminum) plates are to be press-fitted and seal-welded in the cavities between the double stainless steel walls. In its May 17, 1978 submittal, PSE&G states that stringent in-process inspection and process controls are imposed during manufacturing of the Boral plates to assure that they have a density of at least 0.020 gram of the boron-ten (B-10) isotope per square centimeter of plate. In this full array of storage boxes, there will be two Boral plates between adjacent fuel assemblies. This makes the minimum areal density of boron between fuel assemblies 2.41×10^{21} B-10 atoms per square centimeter.

As stated in PSE&G's February 14, 1978 submittal, the fuel criticality calculations using the proposed new spent fuel racks are based on unirradiated fuel assemblies with no burnable poison and a fuel loading of 44.7 grams of uranium-235 (U-235) isotope per axial centimeter of fuel assembly.

The Exxon Nuclear Company (Exxon) performed the criticality analyses for PSE&G. Exxon's initial calculational method was the KENO-III Monte Carlo program with 18 energy group cross sections, which were obtained from the CCELL, BTR-I and GAMTEC-II programs. These programs were used to determine the effects on the effective multiplication factor (Keff)* in the SFP of mechanical tolerances, fuel and boron loading tolerances, temperature, and fuel density. Exxon then used the KENO-IV Monte Carlo program, with 123 energy group cross sections,

*Keff, effective multiplication factor, is the ratio of neutrons from fissions in each generation to the total number lost by absorption and leakage in the preceding generations. To achieve criticality in finite system, Keff must equal 1.0.

which were obtained from the NITAWL and XSDRN programs, to calculate the Keffs for the nominal spent fuel storage lattice and for a postulated worst case, wherein the worst case geometry was assumed along with a 100°C temperature for the water between the fuel assemblies, while the water in the fuel assemblies was assumed to be 20°C. Exxon's calculated value for this worst case Keff is 0.923.

Exxon checked the accuracy of this KENO-IV method by calculating two types of experiments, which were done at the Oak Ridge National Laboratory by E. B. Johnson and G. E. Whitesides. One type was an arrangement of stainless steel clad, uranium dioxide fuel pins in unborated water. The other type was an arrangement of uranium metal fuel pins in unborated water on both sides of a central Boral plate which had a density of 3.8×10^{21} atoms of B-10 per square centimeter. The maximum difference between the calculated and experimental values of Keff was found to be 0.013Δk (or about 1.3 percent).

These storage racks are designed to prohibit the insertion of a fuel assembly anywhere except in prescribed locations. In its May 17, 1978 response to our request for additional information, PSE&G stated that it is not possible to place a fuel assembly either between storage rack modules or between the outer periphery of the storage racks and the spent fuel pool walls.

In response to our request for additional information, PSE&G stated in its May 17, 1978 submittal that neutron transmission tests will be performed on the completed rack modules to verify the presence of all the Boral plates in the racks prior to placing any fuel in the racks.

The above results compare favorably with the results of calculations made with other methods for similar fuel pool storage lattices which also assumed new, unirradiated fuel with no burnable poison or control rods in unborated water. These calculations yield the maximum neutron multiplication factor that could be obtained throughout the life of the fuel assemblies. This includes the effect of the plutonium which is generated during the fuel cycle.

The NRC acceptance criterion for the criticality aspects of fuel storage in high density fuel storage racks is that Keff shall not exceed 0.95, including all uncertainties, under all conditions throughout the life of the racks. This acceptance criterion is based on the overall uncertainties associated with the calculational methods, and it is our judgment that this provides sufficient margin to preclude criticality in fuel pools. A technical specification which limits Keff in spent fuel pools to 0.95 will be provided to assure this criterion is adhered to.

Since the maximum Keff that could be experienced in spent fuel pools can not practicably be measured (considering at any one time only a limited number of fuel assemblies, mostly irradiated ones, will be in the pool), it is prudent to use a calculated Keff. To preclude any unreviewed increase, or increased uncertainty, in the calculated value which could raise the actual Keff without it being detected, a limit on the maximum fuel loading is also required. Accordingly, we find that the proposed high density storage racks will meet the NRC criterion when the fuel loading in the assemblies described in these submittals is limited to 44.7 grams or less of U-235 per axial centimeter of stored fuel assembly. This restriction will be imposed by a Technical Specification change.

2.1.1 Conclusion

We find that when any number of the Salem plant fuel assemblies, which PSE&G states will have no more than 44.7 grams of U-235 per axial centimeter of fuel assembly, are loaded into the proposed racks, the Keff in the fuel pool will be less than the 0.95 limit. We also find that in order to preclude the possibility of the Keff in the fuel pool exceeding 0.95 without being detected, it is prudent to prohibit the use of these high density storage racks for fuel assemblies that contain more than 44.7 grams of U-235 per axial centimeter of fuel assembly. On the basis of the information submitted, and the Keff and fuel loading limits stated above, we conclude that there is reasonable assurance that the use of the proposed racks will not result in a criticality.

2.2 Spent Fuel Cooling

The licensee considered the additional heat load that would result from the additional fuel assemblies that will be stored in the SFP and calculated the effect of this heat load on the SFP cooling system. A description of the various assumptions considered in this review and the maximum heat loads expected are discussed below.

The licensed core power for Salem Unit No. 1 is 3338 thermal megawatts (MWt). PSE&G plans to refuel annually. This will require the replacement of about 65 of the 193 fuel assemblies every year. In its February 14, 1978 submittal, PSE&G assumed a 150-hour decay time after 1095 effective full power days (EFPD) of reactor operation to calculate the maximum in-pool heat generation rates per fuel assembly. Using the method given on pages 9.2.5-8 through 14 of the NRC Standard Review Plan with the above assumptions, PSE&G calculated a decay heat load of 55.4 kw for an average power fuel assembly. Using this same method, PSE&G calculated that the maximum SFP heat load during the 18th annual refueling, i.e., the one that fills the pool, will be 18.6 x 10^6 Btu/hr (5.45 MWt).

The SFP cooling system consists of two pumps and one heat exchanger. Each pump is designed to pump 2300 gpm (1.15 x 106 pounds per hour). The heat exchanger is designed to transfer 11.9 x 10^6 Btu/hr (3.35 MWt) from 120°F fuel pool water to 95°F component cooling water, which is flowing through the heat exchanger at a rate of 1.49 x 10^6 pounds per hour.

Should a full core offload be required, PSE&G states that the core would be cooled in the reactor vessel with the residual heat removal system until the SFP cooling system could keep the outlet water temperature from exceeding 150°F. At 150°F, the SFP cooling system will transfer 26.38 x 10^6 Btu/hr (7.36 MWt). For a full core offload after 15 annual refuelings, PSE&G calculated that 570 hours (about 22 days) of decay time would be required before the SFP cooling system, with only one pump operating, would keep the outlet water temperature below 150°F.

2.2.1 Evaluation

PSE&G's calculated fuel pool outlet water temperatures are consistent with the stated cooling water flow rates and the design of the heat exchanger. We calculate that with one pump running at its design capacity and the 150 hour decay heat load in the pool at the 18th refueling (i.e., 18.6 x 10^6 Btu/hr) the maximum spent fuel pool outlet water temperature will be about 134°F, which is consistent with the licensee's calculations.

As stated in Section 9 of the FSAR, up to 100 gpm of makeup water for the SFP is available from the refueling water storage tank, which is designed to seismic Class I criteria. We find that PSE&G's calculated peak heat loads for the SFP with modified racks are conservative and acceptable. We also find that the maximum incremental heat loads that will be added by increasing the number of spent fuel assemblies in the SFP from 264 to 1170 will be 4.5 x 10^6 Btu/hr. This is the difference in peak heat load for a full core offload that essentially fill the present and the modified pool. The total peak heat load resulting from a full core offload will be 42.1 x 10^6 Btu/hr for the modified design as compared to 37.6 x 10^6 Btu/hrs for the existing rack design. For the full core offload that fills the pool (i.e., 15 prior annual refuelings), we calculate that the maximum required cooling time in the reactor vessel that will be needed to keep the spent fuel pool water temperature below 150°F with only one spent fuel pool cooling pump running will be about the same as the 570 hours calculated by PSE&G. Therefore, the maximum delay in removing a full core from the reactor vessel would be about 22 days.

Assuming an SFP water temperature of 150°F, the minimum possible time to achieve bulk pool boiling after any credible additional failure in the SFP cooling system would be about six hours. After bulk boiling commenced, the maximum evaporation rate would be about 56 gpm. We find that six hours would be sufficient time for PSE&G to establish a 56 gpm makeup rate. We also find that under bulk boiling conditions the surface temperature of the fuel will not exceed 350°F. This is an acceptable temperature from the standpoint of fuel element integrity and surface corrosion.

2.2.1 Conclusion

We find that the present cooling capacities in the spent fuel pool of the Salem Unit No. 1 will be sufficient without modification to handle the incremental heat load that will be added by the proposed modifications. We also find that this incremental heat load will not alter the safety considerations of spent fuel pool cooling from that which we previously reviewed and found to be acceptable.

2.3 Installation of Racks and Fuel Handling

PSE&G's present plans are to modify the spent fuel storage racks at both Salem Nuclear Generating Station Units 1 and 2 prior to offloading spent fuel into either pool. If these plans are realized, at the time of the modification, the pools will not be contaminated with radioactivity and the racks can be changed without having water in the pools.

Since there would be no fuel assemblies in the fuel pool during the modification, it would not be possible to have an accident involving radioactivity. In the event that the modifications are not performed until after the first refueling outage for either Unit 1 or 2, PSE&G will be required to provide the staff with its intended procedures and safety precautions that will be used to ensure that an accident involving irradiated fuel does not occur.

After the new racks are installed in the pool, the fuel handling procedures that will be implemented in and around the pool will be the same as those procedures that were in effect prior to the modifications. These were previously reviewed and found acceptable by the NRC.

The spent fuel handling equipment has a separate spent fuel cask loading pool adjacent to the spent fuel pool, connected by a canal. Mechanical stops on the crane prevent passage of a spent fuel cask over or near the spent fuel pool.

Even if the modification were to be performed with water in the spent fuel pool, and should the cask drop or tip while in the handling building, any resultant water loss from the cask loading pit would neither create a safety hazard nor affect other safety-related equipment. Since two gates separate the cask loading pit from the spent fuel pool, water leakage from the spent fuel pool in the event of a cask drop directly over the loading pit will be prevented.

The NRC staff has under way a generic review of load handling operations in the vicinity of spent fuel pools to determine the likelihood of a heavy load impacting fuel in the pool and, if necessary, the radiological consequences of such an event. At present Salem 1 is prohibited by its technical specifications from the movement of loads with weight in excess of 2500 pounds over spent fuel assemblies in the SFP.* This restriction is to limit the maximum weight, i.e., a fuel assembly, that can be carried over the stored fuel assemblies until our generic review is completed. There are two other lighter loads, however, identified by the licensee, that are handled over stored fuel assemblies. These loads are the Fuel Assembly Handling Fixture and Burnable Poison Rod Assembly Tool. Although lighter than a single fuel assembly, these two loads could develop greater kinetic energy should they be dropped because of greater potential drop heights. This larger kinetic energy could theoretically cause more damage to stored fuel assemblies than that calculated assuming a single dropped fuel assembly. The licensee has therefore examined the use of these loads and has provided the information presented in Table 2.3-1.

As indicated, the maximum potential kinetic energy of an unloaded Fuel Assembly Handling Fixture is approximately twice that of a fixture when carrying a fuel assembly. And the maximum potential energy contained in the Burnable Poison Rod Assembly Tool is approximately four (4) times that of a dropped fuel assembly and handling fixture.

Based on the breaking strength of the wire rope reeving system, the design factor when handling an unloaded fixture or tool is 160:1 and 86:1, respectively. Further, the licensee points out

*Salem Unit 1 Technical Specifications, Section 3.9.7.

that whereas the fuel handling crane is limited to handling loads not exceeding 2500 pounds it is rated and tested, per OSHA (ANSI B 30.2) requirement, for 10,000 pounds (5 tons). In addition, as indicated in Table 2.3-1, the design factors for the attachment points for the fixture and tool (in an unloaded condition) are 28:1 and 17:1, respectively.

Based on the above, we believe that the likelihood of a drop of the unloaded fixture or tool due to either a structural failure of the crane or reeving components is very remote because of the existing large design margins. In addition to the design factors indicated above, to preclude a load drop due to it becoming disengaged from the crane hook, or failure of the hook itself, the licensee has indicated that it will provide a back up means of supporting the fixture or tool, as illustrated in Figure 2.3-1 (as provided in the licensee's December 22, 1978 submittal), in addition to the hook-throat latch type safety hook. This backup cable sling will have a safety factor comparable to the crane, i.e., 5:1. Therefore, if the tool or fixture should be improperly engaged or otherwise become disengaged from the crane hook, there is reasonable assurance that, it would be supported by the wire rope backup cable and is, therefore, acceptable.

The fuel handling crane is rated for 5 tons and tested in accordance with OSHA (ANSI B 30.2) requirements. The ratio of the weight of the unloaded fixture and tool to the cranes rated load capacity is 1:31 and 1:15, respectively. These margins, in our view, are sufficient to preclude their dropping due to a structural crane failure.

2.3.1 Conclusion

The consequences of fuel handling accidents in the spent fuel pool area are not changed from those presented in the Safety Evaluation Report dated October 1974. This design basis accident is independent of the number of fuel assemblies in the pool and is defined for fuel with the least decay after shutdown for refueling. The accident is assumed to occur at a time after shutdown identified in the Technical Specifications as the earliest time fuel handling operations may begin. The Technical Specifications which prohibit loads greater than 2500 pounds allow flexibility in the movements of fuel and other relatively light loads, while providing reasonable assurance that the consequences of the design basis accident will not be exceeded.

Table 2.3-1

	Fuel Assembly Handling Fixture	Burnable Poison Rod Assembly Tool
Maximum Drop Height of Empty Tool over storage racks, ft.	15	15
Weight of Empty Tool, lbs.	350	650
Maximum Kinetic Energy at Impact, ft. lbs.	5250	9750
Maximum Drop Height of Loaded Tool over storage racks, ft.	1 1/4	1 1/4
Maximum Weight of Loaded Tool, lbs.	1965	2265
Maximum Kinetic Energy at Impact ft. lbs.	2456	2831
Unloaded Tool, Wire Rope Design Factor (based on breaking strength) - Reeving system	350/56000	650/56000
Loaded Tool, Wire Rope Design Factor (based on breaking strength) - Reeving system	1965/56000	2265/56000
Design Factor of remaining portions of fuel handling crane with respect to its load rating of 5 tons	5:1	5:1
Design Factor of Tool Inducing the Connection Point (loaded condition)	5:1	5:1
Design Factor of Tool Including the Connection Point (unloaded condition)	28:1	17:1

Note 1: Fuel Handling crane is load tested per Chapter 2-2 of ANSI B30.2

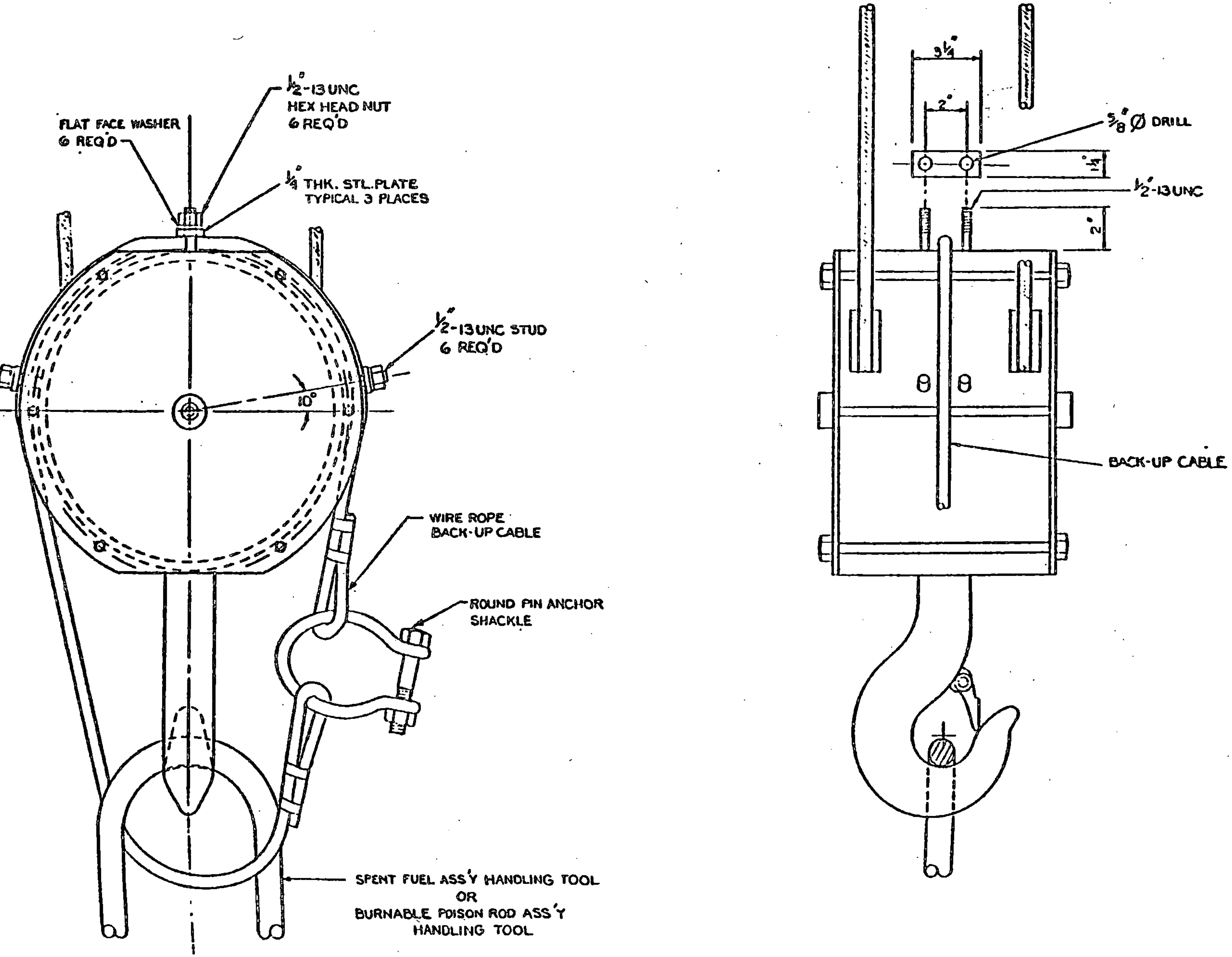
1/2"-13 UNC
HEX HEAD NUT
6 REQ'D
FLAT FACE WASHER
6 REQ'D
1/4" THK. STL. PLATE
TYPICAL 3 PLACES
1/2"-13 UNC STUD
6 REQ'D
10°
WIRE ROPE
BACK-UP CABLE
ROUND PIN ANCHOR
SHACKLE
SPENT FUEL ASS'Y HANDLING TOOL
OR
BURNABLE POISON ROD ASS'Y
HANDLING TOOL
3 1/4"
2"
5/8" Ø DRILL
1 1/4"
1/2"-13 UNC
2"
BACK-UP CABLE

FIGURE 2.3-1

2.4 Structural and Mechanical Design

The current fuel storage racks in the Salem Unit 1 spent fuel pool provides for a storage capacity of 264 fuel assemblies. The proposed modification consists of replacing the existing racks which will provide a storage capacity of 1170 fuel assemblies with a nominal center-to-center spacing between fuel assemblies of 10-1/2 inches. The storage cells are constructed of type 304 stainless steel, aluminum-clad Boral material, with the remaining portions of the rack structures constructed of type 304 stainless steel.

The design uses a stiffened module base which directly supports the fuel assemblies and an upper box structure which contains the spent fuel storage cells. These structures are assembled by welding. The rack bases are supported off the spent fuel pool floor by seven (7) support legs on each module. The upper box structure consists of a top grid assembly, mid-height peripheral members and plate diaphragms (stiffened, where necessary, to prevent shear/compression buckling), and are welded to the module base. Each cell is a square cross section formed from an inner shroud of stainless steel, a center sheet of aluminum clad Boral, and an outer shroud of stainless steel. A flared guide and transition section is provided at the top of each storage cell.

2.4.1 Evaluation
Structural and Mechanical

The supporting arrangements for the modules, including their restraints, the design, the fabrication, the installation procedures, the structural design and analyses procedures for all loadings, including seismic and impact loadings, the load combinations, the structural acceptance criteria, the installation, and the applicable industry codes were all reviewed in accordance with the applicable portions of the NRC OT Position for Review and Acceptance of Spent Fuel Pool Storage and Handling Applications, April 1978.

The fuel pool is located in the Fuel Handling Building. A response spectrum dynamic seismic analysis of the fuel rack structures was performed using horizontal and vertical response spectra as seismic input which conform to those in the Salem FSAR and approved in the staff's SER for Salem Units 1 and 2. The seismic response spectra for the spent fuel storage pool floor were generated from the horizontal and the vertical time-history accelerations calculated at the level of the pool floor in the seismic analysis of the fuel handling building. The seismic modal responses of the racks and the three spatial earthquake components of rack response were combined in accordance with

Standard Review Plan Section 3.7.2 and Regulatory Guide 1.92, Rev. 1, entitled, "Combining Modal Responses and Spatial Components in Seismic Response Analyses."

The damping values utilized in the seismic analysis of the rack modules were consistent with those approved in the Salem FSAR and approved in the staff's SER for Salem Units 1 and 2. No credit was taken for additional damping due to the racks being submerged in water. The amount of mass added to a rack to account for submergence in the pool was taken to be the mass of the water enclosed in the spent fuel pool storage rack.

Time-history analyses were performed to account for the effects of the clearance gap between a storage cell and the fuel assembly contained therein. The analysis was performed using an artificially generated time-history whose response spectrum enveloped the floor level response spectrum for the floor of the Salem fuel storage pools. (The method was the same as that approved previously for Arkansas Nuclear One in the December 17, 1976 NRC Safety Evaluation Report for its spent fuel rack modification.) The results of the analysis were that the maximum combined support reactions calculated were 1.18 times the maximum combined reactions calculated by the simplified linear elastic time-history analysis with no gap between the storage cell walls and the fuel assembly. Therefore, the seismic loads developed by the linear elastic analysis of the complete rack structure were increased by a factor of 1.18. A maximum impact load on the fuel cell associated with the 1.18 impact factor was shown to be much less than the load capability of the fuel cell can walls. No adverse effects on the rack structures or fuel assemblies resulted from these considerations. Time-history analyses were also performed to account for the effect of rack modules potentially sliding on the pool floor and impacting the pool walls at the lower wall restraints. A row of four modules along the length of the pool was modeled.

Each module was modeled as a simplified two degree of freedom system with gap elements included at all thermal expansion gaps and friction elements provided to account for the racks sliding on the pool floor. The time-history used was the same as that developed for the storage cell/fuel assembly analysis. The friction factors between the module feet and the stainless steel floor were taken from General Electric Report No. 60 GL20, "Investigation of the Sliding Behavior of a Number of Alloys Under Dry- and Water-Lubricated Conditions," by R.E. Lee, Jr., January 30, 1960, which was published by General Electric. Subsequent evaluation indicated that the values used are consistent with the values contained in a report entitled, "Friction Coefficients of Water-Lubricated Stainless Steels for a Spent Fuel Rack Facility," by Professor Ernest Robinowicz of the Massachusetts Institute of Technology. This analysis yielded a conservative reaction force at the pool wall which was used in the design of the wall restraints since it is improbable that the racks would slide at all. In addition, the rack module base was analyzed using this impact force directly superimposed on the other seismic and dead weight loads yielding no adverse effects.

The rack material properties for structural components used in the analysis of the fuel racks were taken from Appendix I of Section III of the ASME Boiler and Pressure Vessel Code. The material properties consistent with a temperature of 150°F were used for all load cases at normal operating temperatures and the material properties consistent with a temperature of 240°F were used for the load cases at maximum temperature.

Results of the seismic analysis show that the racks are capable of withstanding the loads associated with all the design loading conditions without exceeding allowable stresses.

The racks were also designed to withstand the local as well as gross effects of the impact of a fuel assembly dropped from a height of 15 inches such that no significant deformation of the rack module configuration will occur for the postulated dropped fuel assembly. The local effects were determined through a test on 2-foot long sections of a Boral poison spent fuel cell together with the flared lead in section to determine the load-deflection characteristics of the cells. Two cases were considered, one where the assembly falls vertically directly on one cell but rotated 45° such that the corners of the assembly hit the side of the cell, and the other where the assembly falls vertically at the center of a group of four cells. The first case results in maximum force and deflection on an individual cell while the second case results in a maximum force being applied to the rack structure. In both cases crushing of the cell was shown to be limited to the upper 7 inches of the lead-in section, above the rack module upper grid structure and above stored fuel assemblies. The effects of a dropped assembly accident inside a storage cell was also evaluated. The impact energy was absorbed by the 1/4-inch base plate and a small amount of bending distortion of the base assembly beam members. In addition, the effects of a dropped assembly accident, in which the assembly rotates as it drops, were evaluated. In this case, the assembly impacts a row of storage cells and comes to rest on top of the rack modules. The results indicate that this case results in lower loads than the simple vertical drop case.

The fuel pool structure consists of concrete walls and floor lined with type 304 stainless steel liner plate. The increase in floor loading due to the proposed spent fuel storage racks is well under 1% of the total mass lumped at the level in the fuel handling building analytical model. The walls have been investigated for the seismic effect of the heavier racks and stored fuel. The new high density racks have no appreciable effect on the structural stability and seismic response of the fuel handling building. The pool structure meets all allowable limits imposed on the design in the FSAR considering any new loadings.

Material Considerations

In August 1978, the staff was made aware of a problem at the Monticello facility that had been identified with regard to spent fuel storage racks similar in design to those proposed for use at Salem Unit No. 1. The problem involved the in-leakage of water into the stainless steel cans, such that hydrogen gas was generated due to oxidation of the exposed aluminum material. This gas caused a pressure buildup and resultant swelling of the stainless steel cans such that the removal of a fuel assembly, if located at an affected storage location, could not be removed. A discussion of how this potential problem has been considered at Salem is provided below.

The Salem high density spent fuel storage cell utilized Boral material sealed between an inner and outer stainless steel shroud. This cell will be supplied to Exxon Nuclear Company by Brooks and Perkins, Incorporated. The stainless steel shroud (or cladding) is type 304. The boral consists of an 1100 series aluminum and boron carbide matrix core sandwiched between two layers of 1100 series aluminum cladding. The stainless steel shrouds are seal-welded together at both ends such that the annulus between the shrouds is leaktight. In the event that there are leaks allowing water to enter the annulus, there will be corrosion of the aluminum with hydrogen gas as an off product. Once the pressure buildup within the composite exceeds 1.8 to 3 psi, the inner shroud will bulge inward and will contact the fuel bundle. In an effort to avoid the consequences of water leakage into the cell annulus, the licensee will impose strict welding procedures, welding operations and qualifications of welders in accordance with the requirements of the ASME Code, Section IX, and nondestructive examination requirements, in accordance with ASME Section X. In addition, leaktightness tests will be conducted using helium mass spectrometer tests to ensure 100% leaktightenss with a 95% confidence level.

The response of a poison spent fuel storage cell to internal pressurization caused by corrosion has been evaluated by Exxon Nuclear Co. in a series of tests which demonstrated that if a leak exists in a fuel storage cell after installation in the water filled pool and before fuel is inserted, the worst consequence would be the inability to insert the fuel into that cell. Secondly, if a leak develops in a fuel storage cell during the operating lifetime of the storage pool and fuel is already in place, the most severe results would be that the fuel could not be withdrawn with the normal fuel withdrawal force limit of the fuel handling machine. In this event, semi-remote tooling will be used to provide vent holes in the top of the storage cell annulus to relieve the pressure on the fuel assembly and permit routine removal.

Based upon our review to date of the corrosion potential in spent fuel pool environments and previous operating experience, we have concluded that at the pool temperature and the quality of the demineralized water (with dissolved boric acid) there is reasonable assurance that no significant corrosion of the stainless steel in the racks, the fuel cladding or the pool liner will occur over the lifetime of the plant, thereby significantly impacting the structural integrity of the racks. Since the possibility of long-term storage of spent fuel exists, the effects of the pool environment on the racks, fuel cladding and pool liner are under continued investigation.

2.4.2 Evaluation Summary

The analyses, the design, the fabrication and the installation of the proposed fuel rack storage system are in accordance with accepted criteria. The analysis of the structural loads imposed by dynamic, static, seismic and thermal loadings, and the acceptance criteria for the appropriate loading conditions, are in accordance with the appropriate portions of the NRC OT Position for Review and Acceptance of Spent Fuel Pool Storage and Handling Applications, April 1978.

The mechanical properties for the materials utilized in the rack design were those consistent with the pool maximum operating temperature of 150°F. The quality assurance procedures for the materials, the fabrication, the installation and the examination of the new rack structures are in acceptable general conformance with the accepted requirements of ASME Code, Section III, Subsection NF, Articles NF-2000, NF-4000 and NF-5000.

The effects of the additional loads on the existing pool structure due to high density storage racks have been examined. The pool structural integrity is assured by conformance with the original FSAR acceptance criteria. In turn, this provides adequate assurance that the pool will remain leaktight.

There is no evidence at this time to indicate that corrosion of the fuel assemblies, the stainless steel rack structures or the fuel pool liner will occur at the temperatures and quality of the demineralized water (with dissolved boric acid) to be maintained in this pool. The welding techniques and procedures and the nondestructive examination techniques provide a high level of confidence that the annuli containing the Boral in the installed cans will be leaktight. Although no leakage is likely to occur, tests were conducted which demonstrated that if isolated cases of leakage should occur in service, any swelling of the cans would not represent a safety hazard.

Upon exposure of the Boral plates (B_4C/Al matrix) to the spent fuel pool water, galvanic coupling between the aluminum-Boral liner, aluminum binder and the stainless steel shroud could occur. Deterioration of the Boral would be limited to edge attack by general corrosion and pitting corrosion of the aluminum liner and binder in the general area of the leak path. The B_4C neutron adsorption particles are inert to the pool water and would become embedded in corrosion products preventing loss of the B_4C particles. Thus, this small amount of deterioration would have no effect on neutron shielding, attenuation properties or criticality safety. The hydrogen produced by corrosion of the aluminum will be released by venting to minimize bulging.

To aid in verifying the above conclusions, the licensee has committed to conduct a long-term fuel storage surveillance program to verify that the spent fuel storage cell retains the material stability and mechanical integrity over the life of the spent fuel storage racks under actual spent fuel pool service conditions. Sample flat plate sandwich coupons and short fuel storage cell sections will be placed in an empty fuel storage cell and periodically examined visually and by weight analysis.

2.4.3 Conclusion

Based on the evaluation presented above, we find that the new proposed Salem spent fuel storage racks and the design and analyses performed for the racks, support frames and pool are in conformance with established criteria, codes and standards.

2.5 Occupational Radiation Exposure

If the modification is accomplished before the first refueling, there should be no occupational exposure associated with the removal, disassembly and disposal of the low density racks and the installation of the high density racks, because both spent fuel pools would be dry and without spent fuel or water containing radioactivity.

If the modification is not accomplished until after the first refueling, there would be some occupational exposure to radiation. Experience at similar facilities where re-racking has occurred has demonstrated that such exposures can be kept to acceptably low levels. Prior experience indicates this should be from about 2 to 5 man-rems. This would represent a small fraction of the total man-rem burden from occupational exposure at the Salem Station. Based on our review, we conclude the exposures from this operation should be as low as reasonably achievable (ALARA).

We have estimated the increment in onsite occupational dose resulting from the proposed increase in stored fuel assemblies at both units on the basis of information supplied by the licensee, and by using relevant assumptions for occupancy times and for dose rates in the spent fuel area from radionuclide concentrations in the SFP water. The spent fuel assemblies themselves contribute a negligible amount to dose rates in the pool area because of the depth of water shielding the fuel. The occupational radiation exposure resulting from the proposed action represents a negligible burden. Based on present and projected operations in the spent fuel pool area, we estimate that the proposed modification should add less than one percent to the total annual occupational radiation exposure burden at both units. The small increase in radiation exposure should not affect the licensee's ability to maintain individual occupational doses to as low as is reasonably achievable and within the limits of 10 CFR Part 20. Thus, we conclude that storing additional fuel in the two pools will not result in any significant increase in doses received by occupational workers.

2.6 Radioactive Waste Treatment

The station contains waste treatment systems designed to collect and process the gaseous, liquid and solid wastes that might contain radioactive material. The waste treatment systems were evaluated in the Salem 1 and 2 Safety Evaluation (SER) dated October 1974 for the station. There will be no change in the waste treatment systems or in the conclusions of the evaluation of these systems in Section 11.0 of the SER because of the proposed modification.

3.0 SUMMARY

Our evaluation supports the conclusion that the proposed modifications to the Salem Unit 1 SFP are acceptable because:

(1) The increase in occupational radiation exposure to individuals due to the storage of additional fuel in the SFP would be negligible.

(2) The installation and use of the new fuel racks does not alter the potential consequences of the design basis accident for the SFP, i.e., the rupture of a single fuel assembly and the subsequent release of the assembly's radioactive inventory within the gap.

(3) The likelihood of an accident involving heavy loads in the vicinity of the spent fuel pools is sufficiently small that no additional restrictions on load movement are necessary while our generic review of the issues is underway.

(4) The physical design of the new storage racks will preclude criticality for any credible moderating condition with the limits to be stated in the technical specifications.

(5) The SFP has adequate cooling with existing systems.

(6) The structural design and the materials of construction are adequate to assure safe storage of fuel in the pool environment for the duration of plant lifetime and to withstand the seismic loading of the design earthquakes.

4.0 CONCLUSION

We have concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (2) such activities will be conducted in compliance with the Commission's regulations and that the proposed action to permit installation and use of high density spent fuel storage racks in the spent fuel pool at the Salem Nuclear Generating Station, Unit 1 will not be inimical to the common defense and security or to the health and safety of the public.

Date: January 15, 1979

APPENDIX E

SALEM NUCLEAR GENERATING STATION
UNIT NOS. 1 AND 2
Fire Protection Safety Evaluation Report

I. INTRODUCTION

We have reviewed the Salem Nuclear Generating Station Unit Numbers 1 and 2 fire protection program and fire hazards analysis submitted by the licensee. The submittal, including their answers to six NRC requests for additional information, was in response to our request to evaluate his fire protection program against the guidelines of Appendix A to BTP APCSB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants." As part of the review, we visited the plant site to examine the relationship of safety related components, systems, and structures in specific plant areas to both combustible materials and to associated fire detection and suppression systems. The overall objective of our review of the Salem Nuclear Generating Plant fire protection program was to ensure that in the event of a fire at either facility, Units 1 and 2 would maintain the ability to safely shutdown, remain in a safe shutdown condition, and minimize the release of radioactivity to the environment.

Our review included an evaluation of the automatic and manually operated water and gas fire suppression systems, the fire detection systems, fire barriers, fire doors and dampers, fire protection administrative controls, fire brigade training, and plant fire protection Technical Specifications.

Since Unit 1 and 2 are of the same design, except where noted, the comments made in this report apply to both units.

Our conclusion, given in Section VII is that the Fire Protection Program at the Salem Nuclear Generating Station Unit Nos. 1 and 2 is adequate at the present time, and meets General Design Criterion 3. However, to further ensure the ability of the plant to withstand the damaging effects of fires that could occur, we are requiring, and the licensee has agreed to provide, additional fire protection system improvements. Until the committed fire protection system improvements are operational, we consider the existing fire detection and suppression systems; the existing barriers between fire areas; improved administrative procedures for control of combustibles and ignition sources; the trained onsite fire brigade; the capability to extinguish fires manually; and the fire protection technical specifications provide adequate protection against a fire that would threaten safe shutdown. These additional fire protection features will be completed for Unit Number 1 prior to the end of its second refueling outage. For Unit Number 2, the program will be implemented prior to the first refueling outage. The schedule for specific protection system improvements is presented in Table I at the end of this report.

This report summarizes the results of our evaluation of the Fire Protection Program at the Salem Nuclear Generating Station.

II. FIRE PROTECTION SYSTEMS DESCRIPTION

A. Water Supply Systems

The water supply system is common to both units and consists of two full capacity 2500 gpm diesel engine driven fire pumps, and a separate motor driven pressure maintenance (jockey) pump whose capacity is 30 gpm at 110 psig. Each pump has its own driver with independent power supplies and controls. Separate pump discharge headers connect to the yard fire main loop at points approximately 5 feet apart and are underground. Post indicator valves are provided to isolate the pump discharge headers in the main yard loop. They are also provided to isolate sections of the fire loop for maintenance and repair.

The two fire pumps, their associated fuel oil day tanks, the jockey pump and the station fresh water pumps are located in the fire pump house. The fresh water pumps are separated from the fire pumps by a three hour barrier. The fire pump room is protected by a wet pipe sprinkler system with heat actuated sprinkler heads. Floor drains are provided which would limit the spread of oil in the event of a leaking oil tank. The fire pumps are mounted on 12-inch high concrete foundations. Separate alarms monitoring pump running, prime mover availability, or failure to start are provided for the pumps in the plant control room. The fire pumps are installed in accordance to the applicable sections of NFPA 20. We have evaluated the above design and criteria and found that it is an acceptable alternative to locating the equipment in separate rooms.

The water supply source is from two 350,000-gallon fresh water tanks of which 300,000 gallons in each is reserved for fire protection. Make-up to the tanks is supplied from on-site production wells. The fire pumps can take suction from either or both tanks. The fire suppression system requiring the greatest water demand is the deluge system for the main transformers. This water demand is 1400 gpm at 70 psig plus 1000 gpm for the hose streams. This is within the design capacity of 2500 gpm for the system.

We have reviewed the design criteria and bases for the water supply systems and conclude that these systems meet the guidelines of Appendix A to Branch Technical Position 9.5-1 and are, therefore, acceptable.

B. Automatic Sprinkler and Manual Water Systems

The automatic sprinkler system and manual hose station hose standpipe system are fed by the main yard loop with multiple connections to interior fire protection systems header, e.g., the auxiliary building, turbine building, service building and reactor building. Each sprinkler system and manual hose station has an independent connection to the fire protection header fed from two directions, therefore, a single failure cannot impair both the primary and backup fire protection system.

Valves in the fire protection system which are not electrically supervised, with indication in the control room, will be locked and supervised in their normal operating position and checked periodically.

The automatic sprinkler systems, i.e., wet sprinkler system, preaction sprinkler systems, deluge and water spray systems, are designed to the requirements of NFPA Standard No. 13, "Standard for Installation of Sprinkler Systems," and NFPA Standard No. 15, "Standard for Water Spray Fixed System."

Manual hose stations are located throughout the plant to ensure that an effective hose stream can be directed to any safety related area in the plant. These systems are consistent with the requirements of NFPA Standard No. 14, "Standpipe and Hose System for Sizing, Spacing, and Pipe Support Requirements."

Areas that have been equipped or will be equipped* with automatic water suppression systems are:

(A) Water-Operated Deluge Systems

Deluge systems actuated by water-pilot line automatic sprinkler heads are provided for the following equipment areas:

(1) Nos. 11 and 12 Turbine Oil Storage Tanks

(2) No. 1 Seal Oil Unit

(3) No. 1 Turbine Oil Reservoir

(4) No. 1 Turbine Oil Makeup Tank

(5) Nos. 11A and 11B Feedwater Pump Turbine Oil Coolers

(6) No. 1 Turbine Oil Conditioner

(7) No. 1 Feedwater Pump Lube Oil Tank

*To be installed in accordance with Table 1.

(8) Nos. 1, 2 and 3 Station Air Compressors

(9) Nos. 21 and 22 Turbine Oil Storage Tanks

(10) Nos. 2 Seal Oil Unit

(11) No. 2 Turbine Oil Reservoir

(12) Nos. 21A and 21B Feedwater Pump Turbine Oil Coolers

(13) No. 2 Feedwater Pump Lube Oil Tank

(14) No. 2 Turbine Oil Conditioner

(B) <u>Electrically-Operated Deluge Systems</u>

Re-cycling deluge systems actuated by continuous strip overheat detectors are provided for the following equipment areas:

(1) No. 1 Control Room Emergency Air-Conditioning Unit Charcoal Filter

(2) No. 14 Auxiliary Building Standby Ventilation Unit Charcoal Filter

(3) No. 1 Containment Pressure Relief Unit Charcoal Filter

(4) No. 12 Fuel Handling Area Ventilation Unit Charcoal Filter

(5) Nos. 11 and 12 Iodine Removal Units Charcoal Filters

(6) No. 2 Control Room Emergency Air Conditioning Unit Charcoal Filter

(7) No. 24 Auxiliary Building Standby Air-Conditioning Unit Charcoal Filter

(8) No. 2 Containment Pressure Relief Unit Charcoal Filters

(9) No. 22 Fuel Handling Area Ventilation Unit Charcoal Filter

(10) Nos. 21 and 22 Iodine Removal Units Charcoal Filters

(C) Air Operated Deluge Systems

Deluge systems actuated by air-pilot automatic sprinkler heads are provided for the following equipment areas:

(1) No. 1 Main Transformer, Phases A, B, and C

(2) Nos. 11, 12, 13 and 14 Reactor Coolant Pumps

(3) Nos. 11 and 12 Station Power Transformers

(4) No. 1 High and Low Pressure Turbine Bearing Housings

(5) No. 1 Auxiliary Transformer

(6) Heating Boiler Fuel Oil Pump and Heater

(7) No. 2 Main Transformer, Phases A, B, and C

(8) Nos. 21, 22, 23 and 24 Reactor Coolant Pumps

(9) Nos. 21 and 22 Station Power Transformers

(10) No. 2 High and Low Pressure Turbine Bearing Housings

(11) No. 2 Auxiliary Transformer

(D) Wet-Pipe Sprinkler Systems

Wet-pipe sprinkler systems, consisting of piping systems which are filled with water, which will spray from heat actuated sprinkler heads, are provided for the following areas:

(1) Service Building - Elev. 88 ft., 100 ft., 113 ft., and 127 ft., and the cable vaults carrying cables between the Auxiliary Building and the Turbine Building.

(2) Fire Pump House - Elev. 100 ft.

(3) Heating Boiler House - Elev. 100 ft.

(4) No. 1 Turbine Perimeter - Elev. 88 ft., 100 ft., and 120 ft.

(5) No. 2 Turbine Perimeter - Elev. 88 ft., 100 ft., and 120 ft.

(6) Auxiliary Building Drumming and Baling Storage Area - Elev. 100 ft.

(7) Auxiliary Building Resin Storage Areas - Elev. 122 ft.

(8) Auxiliary Feed Pump/Remote Shutdown Panel - Elev. 84 ft.*

(9) Charging Pump - Elev. 84 ft.*

We have reviewed the design criteria and bases for the water suppression systems and conclude that these systems with the additional sprinkler systems to be installed meet the guidelines of Appendix A to Branch Technical Position ASB 9.5-1 and are in accordance with the applicable portions of the National Fire Protection Association (NFPA) Codes, and are, therefore, acceptable.

C. Gas Suppression Systems

Total flooding low pressure CO_2 and/or Halon systems are provided for the following areas:

(A) Automatically-Actuated Carbon Dioxide Flooding Systems

Automatically-actuated flooding systems are provided for the following areas:

(1) Nos. 1A, 1B, and 1C Diesel-Generator Rooms and D.G Control Rooms- Elev. 100 ft. and Day Tank Areas - Elev. 122 ft.

*To be installed in accordance with schedule in Table I.

(2) Nos. 11 and 12 Diesel Fuel Oil Storage Tanks

(3) No. 1 Exciter Enclosure Elev. 140 ft.

(4) Diesel Fuel Oil Transfer Pump Rooms (Unit No. 1) - Elev. 84 ft.

(5) Nos. 2A, 2B, and 2C Diesel-Generator Rooms and Control Rooms - Elev. 100 ft. and Day Tank Areas - Elev. 122 ft.

(6) Nos. 21 and 22 Diesel Fuel Oil Storage Tanks

(7) Diesel Fuel Oil Transfer Pump Rooms (Unit No. 2) - Elev. 84 ft.

(8) No. 2 Exciter Enclosure - Elev. 140 ft.

(B) Automatically Actuated Halon Flooding Systems

(1) No. 1 Relay Room - Elev. 100 ft.*

(2) No. 2 Relay Room - Elev. 100 ft.*

(c) Manually Actuated Carbon Dioxide Flooding Systems

Manually-actuated flooding systems are provided for the following areas:

(1) No. 1 460V Switchgear Room - Elev. 84 ft.

(2) No. 1 4160V Switchgear Room - Elev. 64 ft.

(3) No. 1 Electrical Penetration Area - Elev. 78 ft.

(4) No. 2 460V Switchgear Room - Elev. 84 ft.

(5) No. 2 4160V Switchgear Room - Elev. 64 ft.

(6) No. 2 Electrical Penetration Area - Elev. 78 ft.

---

*To be installed in accordance with schedule given in Table I.

These systems are designed to flood the protected areas with carbon dioxide in concentrations up to 50 per cent. Carbon dioxide fire protection for all areas, except the Exciter Enclosures, is supplied from a 10-ton Cardox refrigerated storage tank (one per unit) located on Elev. 84 ft. of each Auxiliary Building outside the Diesel Fuel Oil Pump Rooms and is discharged to the protected areas either automatically or manually as indicated above. The carbon dioxide fire protection for the Generator Exciter Enclosure for each unit is supplied from a 750-lb. refrigerated storage tank located on Elev. 120 ft. in each Turbine Area. Each tank contains a sufficient supply of carbon dioxide for two full discharges into the largest protected area.

There are three diesel generator sets per unit and each set is flooded by independent CO_2 actuation. The CO_2 system for each Diesel-Generator Room and its associated Control Room and day tank area are actuated together. The CO_2 system for the two Diesel Fuel Oil Pump Rooms for each unit are also actuated together. All other areas are independently actuated.

The CO_2 suppression system is designed in accordance with NFPA Standards Numbers 12 and 12A. We have reviewed the design criteria and basis for these fire suppression systems. We conclude that these systems satisfy the provisions of Appendix A to Branch Technical Position 9.5-1 and are, therefore, acceptable.

D. Foam Suppression System

A manually actuated foam system with a capacity of 300 gallons is located in a Foam Tank House south of the Turbine Area, for the protection of No. 1 Fuel Oil Storage Tank. The system has been designed and installed in accordance with NFPA Standard No. 11 to cover the liquid surface in 30 minutes. The foam solution is double strength, 3% protein foam concentrate.

We have reviewed the design criteria and bases for the foam suppression system and we conclude that the system satisfies the provisions of Appendix A to Branch Technical Position 9.5-1 and is, therefore, acceptable.

E. Fire Detection Systems

The fire detection system consists of the detectors, associated electrical circuitry, electrical power supplies, and the fire annunciation panel. The types of detectors used at the Salem Nuclear Generating Station are ionization (products of combustion), and thermal (heat sensors). The system is continuously supervised with a NFPA 72D Class B supervised system.

Fire detection systems will give audible and visual alarm and annunciation in the control room. Local audible and/or visual alarms are also provided.

The licensee has agreed to install additional smoke detectors in the following areas:

(a) Peripheral rooms of the control room complex - Elev. 122 ft.

(b) Spent and new fuel storage area

(c) Piping penetration area - Elev. 78 ft.

(d) Control Area Air Conditioning System Equipment

(e) Corridor Area - Elev. 100 feet

(f) Resin Storage

(g) Auxiliary Building Ventilation Equipment

(h) Boric Acid Pumps

(i) Safety Injection Pumps

(j) Component Cooling Pumps

(k) Auxiliary Feedwater Pumps

(l) Charging Pumps

(m) Containment Spray Pumps

(o) Storage Tank Recirculation Pumps

(p) Residual Heat Removal Pumps

(q) Emergency Air Compressor

(r) Chilled Water System Chillers

(s) Mechanical Penetration Area

(t) Piping Penetration Area (Elev. 78 ft.)

(u) Inner Piping Penetration Area

(v) Outer Piping Penetration Area

(w) General Containment (one detector in each recirculating fan)

(x) Reactor Coolant Pumps

(y) Service Water Pumps

We have reviewed the fire detection systems to ensure that fire detectors are located to provide detection and alarm of fires that could occur. We have also reviewed the fire detection systems design criteria and bases to ensure that it conforms to the applicable sections of NFPA No. 72D. We conclude that the design and the installation of the fire detection systems with the additional detectors to be installed, meet the guidelines of Appendix A to Branch Technical Position ASB 9.5-1 and the applicable portions of NFPA No. 72D, and are, therefore, acceptable.

III. OTHER ITEMS RELATING TO THE STATION FIRE PROTECTION PROGRAM

A. Fire Barriers

All floors, walls, and ceilings enclosing separate fire areas are rated at a minimum of 3-hour fire rating with exception of the penetrations discussed in Sections III, B and C. The main control room area contains peripheral rooms which are located within the main control room 3-hour fire barrier. These peripheral rooms are provided with detectors and alarms and minimum one-hour fire rated ceilings and fire doors.

The licensee has provided acceptable documentation to substantiate the fire rating of the 3-hour barriers.

B. Fire Doors and Dampers

We have also reviewed the placement of the fire doors to ensure that fire doors of proper fire rating have been provided. The fire rating of the doors as a minimum will be 1-1/2 hour rating based on the fire loading of the particular fire areas.

Ventilation penetrations through barriers are protected in some areas by standard fire door/dampers. The licensee will provide one of the following for the rest of the unprotected ventilation penetrations:

1. UL listed fire rated door type dampers at each penetration.
2. Coat the ventilation ducts with a flame retardant material to a minimum fire rating of 1-1/2 hours based on the fire loading of the area. In addition the licensee will provide rated fire dampers on all supply and exhaust openings in the ducts.

The licensee has provided the necessary information to demonstrate to our satisfaction that fire door/dampers and their method of installation can provide a fire rating equivalent to the fire barrier or the fire loading of the fire area. The fire door/dampers are and will be installed in accordance with NFPA 90-A.

C. Penetration Fire Stops

Penetrations, including electrical penetration seals, through rated barriers are sealed to provide fire resistance equivalent to the barrier itself. The licensee has provided the necessary information to demonstrate that the penetration seals used in the penetrations for cable trays, conduits, and piping and their method of installation can provide a fire rating equivalent to the fire barrier.

We conclude that the fire barriers, barrier penetrations, fire doors and dampers with the additional doors and dampers to be installed meet the guidelines of Appendix A to Technical Position ASB 9.5-1 and are, therefore, acceptable.

D. Communication Systems

Fixed emergency communication using voice-powered head sets is available at specific locations throughout the station. There is also a public address system on each unit which is powered by an inverter normally fed from the 230 volt alternating current vital bus C and backed up by the 125 volt direct current emergency bus C. To satisfy the guidelines of Appendix A to BTP ASB 9.5-1, the licensee has committed, at our request, to provide an additional communication system consisting of portable radio units. To preclude a single electrical failure from causing the loss of all communication systems, the licensee has documented that the fixed repeater and other accessories associated with the portable radio communication system of each unit will be powered from a different 125 volt direct current emergency bus as that of the public address system for that unit.

The licensee has committed to perform a preoperational test to demonstrate that the frequencies used will not affect the actuation of protective relays. We conclude that the addition of this new communication system satisfies our guidelines set forth in Appendix A to Branch Technical Position APCSB 9.5-1 and therefore is acceptable.

E. Reactor Coolant Pressure Boundary Integrity

We expressed a concern to the licensee that spurious valve operation caused by fire may affect theintegrity of the reactor coolant pressure boundary. We required that the licensee examine each interface at the reactor coolant pressure boundary and either demonstrate the capability of the design to withstand spurious valve operation caused by fire without the loss of reactor coolant pressure boundary integrity, or modify the design to assure integrity.

The examination performed by the licensee revealed that the pressurizer relief lines having the electrically and pneumatic operated valves and which are connected to the pressurizer relief tank, were the only interfaces which were not isolated from the high pressure reactor coolant system by two normally closed valves. Each of the two pressurizer relief lines in Unit 1 has a normally closed pneumatic operated relief valve in series with a normally open motor-operated valve. Each pressurizer relief line in Unit 2 has one more pneumatic operated valve per line than Unit 1. This additional valve is normally closed and connected in parallel with the other air operatea valve.

The spurious opening of a single pneumatic operated relief valve caused by a fire could lead to compromising the reactor coolant boundary integrity if the valve is not closed before the design pressure limits of the pressurizer relief tank are exceeded. Each pressurizer relief line can be isolated by either closing the pneumatic or motor operated valve from the main control room or from the corresponding power distribution and motor control centers. The licensee contends that there is sufficient time available to diagnose the situation and isolate the relief line while the pressurizer is relieving to the pressurizer relief tank.

Our review determined that the existing provisions and future modifications for fire protection in the relay room and other areas of the station where the electrical circuits and cables associated with the pressurizer relief valves are located, are consistent with minimizing the probability of a fire causing the opening of the pressurizer relief lines, and, therefore, we conclude that the design in this regard is acceptable. Furthermore, the consequences resulting from the spurious opening of a relief valve caused by a fire or other reasons compounded with the failure of the valve to close within the specified time, have been analyzed by the NRC staff. It has been determined that the consequences resulting from this event are satisfactorily mitigated by the engineered safety feature systems.

IV. FIRE PROTECTION FOR SPECIFIC AREAS

A. Relay and Switchgear Rooms

Relay and switchgear rooms containing redundant electrical divisions are provided for each unit. These rooms are separated from each other and the balance of the plant by a minimum of 1-1/2 hour rated fire barriers. The relay and switchgear rooms for Unit 1 are separated from their counterparts in Unit 2 by two 1-1/2 hour rated fire barriers and a common corridor. There are a minimum of two access doors to each of the rooms and the doors are located at opposite ends of the rooms.

Currently a manually actuated total flooding CO_2 system is installed in the switchgear rooms and manual hose stations are provided for the relay rooms. The licensee has agreed, at our request, to provide an automatic Halon system for the relay rooms.

When the Halon system is actuated, the ventilation system isolates the rooms and smoke venting can be initiated by manually actuating the exhaust fan. In addition, smoke detectors are installed that alarm in the control room. The back-up fire suppression system is the hose stations located in the immediate vicinity of the access doors and portable extinguishers.

All power, control, and instrumentation cable have passed the IEEE No. 383 Flame Test. All cable trays within these rooms have a minimum separation distance of 18 inches vertical and 12 inches horizontal, as well as a fire resistant barrier of asbestos woven cloth on the bottom of each tray. The licensee has performed tests to show that the cables used will not propogate a fire from tray to tray with a vertical separation distance of 12 inches. In addition, the higher voltage trays are installed above the lower voltage trays.

The licensee has committed, at our request, to establish an emergency shutdown procedure and necessary modifications to assure the capability to achieve safe shutdown in the event of an exposure fire in these rooms which might disable redundant cable divisions of system necessary for safe shutdown. The applicant will provide an alternative shutdown method for our review. This alternate shutdown method will include where necessary the rerouting of instrumentation cable to the hot shutdown panel. The procedures and modifications for hot and cold shutdown will be implemented by the second refueling for Unit 1 and the first refueling for Unit 2.

We have reviewed the licensee's fire hazards analysis and fire protection provided for the relay and switchgear rooms and consider that appropriate fire protection has been provided and after the modifications and procedures are implemented will conform to the provisions of Appendix A to BTP ASB 9.5-1 and are, therefore, acceptable.

B. Safety Related Pump Areas

In the safety related pump areas, such as the auxiliary feed pump area and the charging pump, the pumps are located in close proximity to each other. Access to the pumps is usually an open corridor. We were concerned that a common exposure fire could jeopardize the safety function of two or more of the pumps. At our request, the licensee has committed to install automatic water sprinkler systems in these areas. In addition, a one hour rated fire barrier or, alternativly, a one-half hour barrier and a sprinkler system will be provided, where necessary, to separate redundant cable trains serving these pumps. Both trains of the auxiliary feedwater system will be protected in this manner.

We have reviewed the licensee's fire hazards analysis for this area and conclude that appropriate fire protection has been provided and after modifications are implemented will meet the guidelines of Appendix A of BTP 9.5-1 and is, therefore, acceptable.

C. Diesel Fuel Oil Storage Rooms

The diesel fuel oil storage area, located on elevation 84, contains two 7-day diesel oil storage tank rooms, two transfer pump rooms, and the plant's CO_2 system 10 ton storage tank. The fire suppression system for this area is an automatic CO_2 total flooding system. We were concerned that a diesel oil fire in the tank rooms or the diesel oil transfer pump rooms could jeopardize the entire plant's CO_2 suppression system, if manual fire suppression systems had to be used. The licensee, at our request, has committed to install, in addition to the CO_2 system, one of the following systems in the diesel storage tank area:

1. An automatic open head deluge or open head spray nozzle system
2. An automatic closed head sprinkler system
3. An automatic AFFF system, the foam being delivered by a sprinkler or spray system.

We have reviewed the licensee's Fire Hazards Analysis for this area and conclude that appropriate fire protection will be provided and after the modifications are implemented will meet the guidelines of Appendix A of BTP ASB 9.5-1 and is, therefore, acceptable.

D. Other Plant Areas

In order to provide a defense-in-depth design so that a fire will not prevent the performance of necessary safe plant shutdown functions, the licensee has committed to perform a fire interaction analysis on all redundant mechanical and electrical systems and components necessary for safe cold shutdown which are separated only by distance and are within 20 feet of each other. The analysis will postulate a fire in installed or transient combustibles and failure of the primary fire suppression system.

Where additional protection and/or separation is required to assure a safe shutdown condition, the applicant has committed to:

(1) relocate one or both divisions to achieve a minimum of 20-ft. separation between divisions, or

(2) provide a one-hour fire rated barrier such as 1" inch ceramic fiber separating one safety related train from the other or from a common exposure fire and area automatic sprinkler systems

will be provided to afford protection against exposure fire at the interactions, or

(3) provide an alternate shutdown method that is independent of the interaction area.

The licensee's Fire Hazards Analysis addresses other plant areas not specifically discussed in this report. The licensee has committed to install additional detectors, portable extinguishers, hose stations, and some additional emergency lighting as identified in the licensee's installation schedule. We find these areas with the commitment made by the licensee to be in accordance with the guidelines of Appendix A of BTP ASB 9.5-1, and the applicable sections of the National Fire Protection Association Code and are, therefore, acceptable.

V. ADMINISTRATIVE CONTROLS

The administrative controls for fire protection consists of the fire protection organization, the fire brigade training, the controls over combustibles and ignition sources, the prefire plans and procedures for fighting fires and quality assurance.

In response to Appendix A to Branch Technical Position ASB 9.5-1, the licensee described his proposed procedures and controls. The licensee has agreed to revise his administrative controls and training procedures to follow supplemental staff guidelines contained in "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance," dated 6/14/77, and implement them by December 31, 1979. The administrative procedures for the control of combustibles and ignition sources is complete for Unit 1 and will be implemented prior to fuel loading for Unit 2. The present fire brigade consists of a trained three-man brigade. The applicant has committed to have a plant fire brigade of at least five members that will be organized to provide immediate response to fires that may occur at the site. The full brigade will be fully trained and on site by December 31, 1979. The plant fire brigade will also be equipped with stored closed circuit oxygen-type breathing apparatus, portable communications equipment, portable lanterns, and other necessary fire fighting equipment. Spare oxygen cylinders and recharge capability are provided to satisfy the guidelines of Appendix A to Branch Technical Position ASB 9.5-1.

The fire fighting brigade participates in periodic drills. Liaison between the plant fire brigade and the local fire departments has been established. The local fire departments have been on plant tours and have also been involved in training sessions with the plant fire brigade.

We conclude that the fire brigade equipment and training conform to the recommendations of the National Fire Protection Association, Appendix A to Branch Technical Position ASB 9.5-1 and supplemental staff guidelines and are, therefore, acceptable.

VI. TECHNICAL SPECIFICATIONS

We have reviewed the plant Technical Specifications issued for Salem Nuclear Generating Station Unit Nos. 1 and 2 and find that they are consistent with our Standard Technical Specifications for fire protection. Following the implementation of the modifications of fire protection systems and administrative controls resulting from this review, the Technical Specifications will be modified accordingly to incorporate the limiting conditions for operation and surveillance requirements to reflect these modifications.

VII. CONCLUSION

The fire protection system for Salem Nuclear Generating Station Unit Nos. 1 and 2 was evaluated and found to meet General Design Criterion 3 "Fire Protection" at the time the original Safety Evaluation Report was issued in October, 1974.

As a result of investigations conducted by the staff on the fire protection systems, fire protection criteria were developed and further requirements were imposed to improve the capability of the fire protection system to prevent unacceptable damage that may result from a fire. At our request, the licensee conducted a re-evaluation of their fire protection system for Salem Units 1 and 2. The licensee submitted in

September, 1977, a Fire Hazards Analysis for both units and subsequently in response to our positions, six revisions to the Analysis. He also has compared his system, in detail, with the guidelines of Appendix A to Branch Technical Position ASB 9.5-1, "Guidelines for Fire Protection for Nuclear Plants."

During the course of our review we have reviewed the licensee's submittals and his responses to our requests for additional information. In addition, we have made two site visits to evaluate the fire hazards that exist in the Salem Nuclear Generating Station and the design features and protection systems provided to minimize these hazards.

The licensee has completed some modifications or proposed to make additional modifications to improve the fire resistance capability for fire doors, dampers, fire barriers and barrier penetration seals.

The licensee has also proposed to install additional sprinkler systems for areas such as the auxiliary feed pump area, charging pump area, and various other areas, as well as an automatic Halon system in the relay rooms. To ensure that fires can be detected rapidly and the plant operators informed promptly, additional detectors will be installed in various areas of the plant.

In addition, the licensee has committed to establish emergency shutdown procedures to bring the plant to safe cold shutdown condition in the event of a damaging fire in the relay rooms, the switchgear rooms and other safety-related areas.

The licensee is committed to making all improvements by the second refueling for Unit 1 and the first refueling for Unit 2, thus meeting his license condition. We have reviewed the licensee's schedule and find it acceptable and have included it in Table I.

We find that the Fire Protection Program for the Salem Nuclear Generating Station with the improvements already made by the licensee, is adequate at the present time and, with the scheduled modifications, will meet the guidelines contained in Appendix A to Branch Technical Position ASB 9.5-1 and meets the General Design Criterion 3 and is, therefore, acceptable.

Until the committed fire protection system improvements are operational, we consider the existing fire detection and suppression systems; the existing barriers between fire areas; improved administrative procedures for control of combustibles and ignition sources; the trained onsite fire brigade; the capability to extinguish fires manually; and the fire protection technical specifications provide adequate protection against a fire that would threaten safe shutdown.

Our overall conclusion is that a fire occurring in any area of either Salem Nuclear Generating Station will not prevent that plant from being brought to a controlled safe cold shutdown, and further, that such a fire would not cause the release of significant amounts of radiation.

TABLE I

MODIFICATION IMPLEMENTATION SCHEDULE

Action Item No.	Planned Action Item Description	Status Unit 1	Status Unit 2
1.	Make organizational revisions to assign the station superintendent responsible for all aspects of firefighting and fire protection.	Completed	Completed
2.	List the Fire Protection Program as "QA Applicable."	Completed	Completed
3.	Perform detailed review of applicable procedures for adequacy in addressing the requirements of Appendix A to Branch Technical Position 9.5-1 and revise as necessary.	Completed	Completed
4.	Replace the wood planks on the new fuel storage pit with wood which has been treated with a flame retardant.	Completed	Completed
5.	Prepare an engineering procedure for performing additional fire hazards analysis to reflect future station modifications.	Completed	Completed
6.	Approximately six (6) fire area boundary doors which are not currently locked or alarmed will be locked, provided with a time delay alarm to indicate in the Control Room when the door has been left open, or routinely inspected by a roving watch. This action will take into account station security plans currently being studied for the Salem Station.	Completed	Completed
7.	Remove the backup hydrogen storage stations from Elev. 122 feet at the west end of the Auxiliary Building, or enclose the present station in a 3-hour fire rated concrete enclosure with forced ventilation to the outdoors.	Completed	Completed
8.	Add a wet pipe sprinkler system for the Dimethylamine storage tanks located in the steam generator blowdown sample rooms, Elev. 100 feet in the Auxiliary Building.	Deleted. Tanks have been removed.	
9. a.	Ionization type fire detectors will be added as indicated in Section II-E of this report to provide general area protection of safety related equipment. These detectors will alarm and annunciate in the Control Room and alarm locally.	Completed	Completed

Action Item No.		Planned Action Item Description	Status Unit 1	Status Unit 2
9.	b.	Installation of additional automatic smoke detectors which alarm and annunciate in the control room, in the following areas:		
		(1) Peripheral rooms within the control room complex in which the operator does not have visual surveillance from the main console.	Completed	Completed
		(2) Piping penetration area elevation 78 feet.	Completed	Completed
		(3) New and spent fuel pool area.	Completed	Fuel Loading
10.		Auxiliary Building floor penetrations for piping, cable, and ventilation ducting that have not been sealed will be sealed with silicone foam to provide a fire stop with a fire rating greater than the area fire area load as reported by the fire hazards analysis.	Completed	Completed
11.		The lower electrical penetration area supply and return air ventilation dampers will be controlled to shut upon a CO_2 discharge into the lower electrical penetration area.	Completed	Completed
12.		Add fire rated ventilation dampers, which will shut by both fusible-link and CO_2 discharge, in the exhaust air duct from each diesel fuel oil storage tank room and each fuel oil transfer pump room.	Completed	Completed
13		Approximately ten (10) additional emergency lights will be installed, as required, to provide for safe evacuation from all areas of the station.	Completed	Completed
14.		Install a hose house at each yard hydrant. Hose house will meet the requirements of NFPA Standard No. 24 except the equipment stored in each house will be that which is necessary and appropriate for the intended application.	Completed	Completed
15.		One (1) fire hydrant, presently specified on the Fire Protection System drawing, Figure D.1-1, that has not been installed, will be installed.	Completed	Completed
16.		Add a second 4-inch diameter water supply header with appropriate isolation valves from the common Auxiliary Building Header to each Reactor Containment upstream of	Completed	Completed

Action Item No.	Planned Action Item Description	Status Unit 1	Status Unit 2
16. (cont'd)	the Containment penetration isolation valve as shown schematically in Figure 3.5-2. Add appropriate 6-inch valves in the Auxiliary Building common fire water supply header.		
17.	The hose standpipe root isolation valves and the yard main post indicator valves will be provided with locking devices.	Completed	Completed
18.	Add one hose station in the mechanical penetration area of each unit near the entrance to the Fuel Handling Building. Provide with 150 ft. lengths of 1-1/2 inch fire hose and adjustable fog pattern electrical safe type nozzles.	Completed	Completed
19.	Extend the existing fire water standpipe in the Auxiliary Building corridor to reach Elevation 122 feet. Add a hose station at Elevation 122 feet with 150 feet of 1-1/2 inch fire hose and an adjustable fog pattern electrical safe type nozzle.	Completed	Completed
20.	Add a fire hydrant in the yard near the Service Water Pump House.	Completed	Completed
21.	Two (2) dedicated air breathing units (Bio-pacs) with two (2) spare cylinders will be stored at the Reactor Containment entrance for each unit on Elevation 100 feet in the Mechanical Penetration Area. This will be accomplished by relocating four (4) of the twenty (20) units presently available at the station.	Completed	Completed
22.	In addition to existing CO_2 type extinguishers, two portable water extinguishers will be placed in the vicinity of the Control Room, Computer Rooms and the Watch Engineer's Office.	1/80	1/80

Action Item No.	Planned Action Item Description	Status Unit 1	Status Unit 2
23.	Instrumentation will be provided in the exhaust air ducts from the Battery Rooms to indicate loss of ventilation flow with annunciation in the Control Room.	Completed	Completed
24.	Add dikes around each emergency air compressor and each chilled water system chiller to contain the spread of lube oil leakage.	Completed	Completed
25.	Provide manually operated isolation dampers in the supply air and return air ventilation ducts serving the Drumming and Baling Area to permit area isolation from the remainder of the Auxiliary Building ventilation systems.	Completed	Completed
26.	Implementation of staff supplemental guidance contained in "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls, and Quality Assurance," dated June 14, 1977 for:		
	a. Administrative Procedures, Fire Brigade Size, and Testing Program	Completed	Completed
	b. Storage of Combustible Material near Safety Related Conduit/Cable or Equipment.	Completed	Completed
27.	Installation of a portable radio system incorporating repeaters as necessary for the fire brigade and operations personnel. Preoperational testing will be performed to demonstrate that the frequencies used will not affect the actuation of protective relays. Fixed repeaters installed to permit use of the portable radios will be protected from exposure fire damage.	Second refueling	First refueling

Action Item No.	Planned Action Item Description	Unit 1	Unit 2
28. a.	Verification that all fire doors used to protect openings in walls containing safety-related equipment and/or conduit/cable have a fire rating of at least 1-1/2 hours and that the rating is commensurate with the fire hazards analysis for the area assuming an exposure fire.	Completed	Completed
b.	Installation of fire doors as a result of 28a above.	1/80	12/79
29. a.	Install in all 3 hour fire barrier ventilation penetrations one of the following designs:	Engineering Solution completed October 1979 Implementation by Second refueling	First refueling
	(1) Rated fire door/dampers in all ventilation penetrations		
	(2) 1-1/2 hour fire retardant coatings on the duct work plus fire dampers at all louvers. The NRC will review the design prior to installation. In addition the following areas will be modified to conform to this position:		
	1. Control Room	Same as above	
	2. Relay Room	Same as above	
	3. Switchgear Rooms	10/80	10/80
	4. Diesel Fuel Oil Storage Area-Inlet and Exhausts	End of first refueling	Fuel loading
	5. Fuel Oil Transfer Pump Room Inlet and Exhausts	End of first refueling	Fuel loading
	6. Radwaste Area (Drumming and Bailing Area)	10/80 (covered under Item 25)	10/80
30.	Installation of fixed 8-hour capacity self-contained emergency lighting of the flourescent or sealed beam type.	Completed	Completed

Action Item No.	Planned Action Item Description	Unit 1	Unit 2
31.	Installation of an outside hydrant for back-up fire suppression for the service water pump house with a hose house over the hydrant and 1-1/2 inch hose preconnected to the hydrant outlet. Also, provisions for a second hose of sufficient length to enable the second hose stream from the hydrant in the event that the second hose must be routed differently and when more than one hose stream is needed to fight the fire.	Completed	Completed
32.	Installation of automatic, zoned, pre-action, dry pipe sprinklers in the following areas:		
	a. Charging Pump Area	Second refueling	First refueling
	b. Auxilia.y Feed Pump Area	Second refueling	First refueling
33.	Installation of an automatic Halon total flooding system in the relay rooms.	Second refueling	First refueling
34.	Installation of additional hose stations near the battery rooms so that the rooms can be reached with a maximum of 100 feet of hose. In addition the hoses will be equipped with the appropriate nozzles to combat electrical fires.	Completed	Completed
35.	The total rerouting of the hydrogen lines to the volume control tank away from safety related equipment, cables, and conduit.	Completed	Completed

Action Item No.	Planned Action Item Description	Unit 1	Unit 2
36.	Installation of one of the following fire suppression systems as back-up to the automatic total flooding CO_2 system for the diesel oil storage tank rooms: a. An automatic open head deluge or open head spray nozzle system. b. An automatic closed head sprinkler. c. An automatic AFFF system, the foam being delivered by a sprinkler or spray system.	10/80	First refueling
37.	Implementation, modification and installation of an alternative shutdown capability so that hot shutdown capability can be maintained and cold shutdown can be accomplished within 72 hours, independent of the relay, switchgear and control rooms. This will include the rerouting of cables where practicable, installation of automatic sprinklers and half-hour fire barriers between redundant trains and equipment located within 20 feet of each other and written procedures.	Implementation by: Second refueling	First refueling

Environmental Consideration

We have determined that the amendment does not authorize a change in effluent types or total amounts nor an increase in power level and will not result in any significant environmental impact. Having made this determination, we have further concluded that the amendment involves an action which is insignificant from the standpoint of environmental impact and, pursuant to 10 CFR §51.5(d)(4), that an environmental impact statement or negative declaration and environmental impact appraisal need not be prepared in connection with the issuance of this amendment.

Conclusions

We have found that the Fire Protection Program for the Salem Nuclear Generating Station with the improvements already made by the licensee, is adequate at the present time and, with scheduled modifications, will meet the guidelines contained in Appendix A to Branch Technical Position ASB 9.5-1 and meets the General Design Criterion 3 and is, therefore acceptable.

We have concluded, based on the considerations discussed above, that: (1) because the amendment does not involve a significant increase in the probability or consequences of accidents previously considered and does not involve a significant hazards consideration, (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (3) such activities will be conducted in compliance with the Commission's regulations and the issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public.

Date: November 20, 1979

ERRATA FOR APPENDIX E

1. Page E-20, Section IV.B, Fourth and Fifth Sentences in First Paragraph

   Replace these two sentences with the following sentence:

   > "In lieu of the two options proposed by the staff (i.e., a one-hour rated fire barrier or a one-half hour barrier and a sprinkler system), we have accepted an equivalent system that consists of a water sprinkler system with redundant valves operated by separate actuators which, in turn, are actuated by redundant fire detectors."

2. Page E-21, Section IV.D(2)

   Replace "provide a one-hour barrier" with "provide a 0.5 hour barrier."

SALEM NUCLEAR GENERATING STATION, UNIT 2

SAFETY EVALUATION REPORT

PART II

TMI-2 ISSUES RELATED TO FUEL LOAD AND

LOW POWER TEST PROGRAM

TABLE OF CONTENTS

PART II

TMI-2 ISSUES

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

LIST OF TABLES

PART II

INTRODUCTION

The TMI-2 related requirements for near-term operating license (NTOL) applications were initially identified in the January 5, 1980 memorandum from the Executive Director for Operations to the Commissioners, "TMI Action Plan Prerequisites for Resumption of Licensing." On February 6, 1980, a revision of this list of requirements based on the latest draft of the Task Action Plans as of February 6, 1980 was prepared and discussed with the Commission. These requirements were listed in two categories; those required prior to fuel load and low power testing operation up to five percent power (designated as FL) and those required prior to operation above five percent power (designated as FP).

This supplement addresses only those TMI-2 related requirements in the February 6, 1980 list of NTOL requirements as required prior to fuel load, identified therein as FL.

These requirements were developed from all available sources such as the recommendations of the Bulletins and Orders Task Force, the Presidential Commission to Investigate TMI-2, and the NRC Special Inquiry Group, and those which resulted from the Lessons Learned Task Force Short Term Recommendations (NUREG-0578), and the Lessons Learned Task Force Final Report (NUREG-0585).

Those requirements in the February 6, 1980 list which resulted from the Lessons Learned Task Force Short Term Recommendations (NUREG-0578), and those resulting from the Advisory Committee on Reactor Safeguards (ACRS) review of that document and the additional requirements of the Director, Office of Nuclear Reactor Regulation, were previously approved by the Commission. On September 27, 1979, a letter was issued transmitting these requirements to all pending operating license applicants. On November 9, 1979, a letter clarifying these requirements was issued to all pending operating license applicants to assist in their understanding of our requirements.

The response of the Public Service Electric and Gas Company to our letters has been the subject of staff review since October 1979. Meetings were held with the applicants in Bethesda on November 20 and December 11, 1979, and February 26, 1980. Site visits were made on January 10 and 11, and February 27, 1980 to check hardware installation, review proposed support centers, and to review specific administrative procedures relating to operating personnel and accident response.

In addition, for all the remaining items in the February 6, 1980 listing of requirements, the staff and the applicants have had ongoing reviews and meetings concerning these requirements and the applicants' responses to these additional items. Further site visits were held, for example, the March 5-7, 1980 visit by a team headed by an Office of Inspection and Enforcement leader and composed of the NRR licensing project manager, the Office of Inspection and Enforcement site representative, and technical members from NRR. They evaluated the onsite and offsite support centers and their staffing and the installed communications system between the plant and NRC Incident Response Center. This evaluation included the review of licensee management organization and managerial capabilities.

Each applicable FL requirement in the February 6, 1980 listing is discussed below and follows the numbering sequence utilized therein. The Table of Contents of Part II of this supplement consists of that action plan listing. Those requirements arising from the previously approved NUREG-0578 are identified by appropriate reference. The discussion of these items includes sections titled Position and Clarification which are repeated from the generic letters to operating license applicants as discussed above.

I OPERATIONAL SAFETY

I.A.1 Operating Personnel and Staffing

I.A.1.1 Shift Technical Advisor (2.2.1.b - NUREG-0578)

POSITION

Each licensee shall provide an on-shift technical advisor to the shift supervisor. The shift technical advisor (STA) may serve more than one unit at a multi-unit site if qualified to perform the advisor function for the various units.

The shift technical advisor shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in the response and analysis of the plant for transients and accidents. The shift technical advisor shall also receive training in plant design and layout, including the capabilities of instrumentation and controls in the control room. The licensee shall assign normal duties to the Shift Technical Advisors that pertain to the engineering aspects of assuring safe operation of the plant, including the review and evaluation of operating experience.

CLARIFICATION

1. Due to the similarity in the requirements for dedication to safety, training and onsite location and the desire that the accident assessment function be performed by someone whose normal duties involve review of operating experiences, our preferred position is that the same people perform the accident and operating experience assessment functions. The performance of these two functions may be split if it can be demonstrated the persons assigned the accident assessment role are aware, on a current basis, of the work being done by those reviewing operating experience.

2. To provide assurance that the STA will be dedicated to concern for the safety of the plant, our position has been that STAs must have a clear measure of independence from duties associated with the commercial operation of the plant. This would minimize possible distractions from safety judgments by the demands of commercial operations. We have determined that, while desirable, independence from the operations staff of the plant is not necessary to provide

this assurance. It is necessary, however, to clearly emphasize the dedication to safety associated with the STA position both in the STA job description and in the personnel filling this position. It is not acceptable to assign a person, who is normally the immediate supervisor of the shift supervisor, to STA duties as defined herein.

3. It is our position that the STA should be available within 10 minutes of being summoned and therefore should be onsite. The onsite STA may be in a duty status for periods of time longer than one shift, and therefore asleep at some times, if the ten minute availability is assured. It is preferable to locate those doing the operating experience assessment onsite. The desired exposure to the operating plant and contact with the STA (if these functions are to be split) may be able to be accomplished by a group, normally stationed offsite, with frequent onsite presence. We do not intend, at this time, to specify or advocate a minimum time onsite.

4. The implementation schedule for the STA requirements is to have the STA on duty by January 1, 1980, and to have STAs, who have all completed training requirements, on duty by January 1, 1981. While minimum training requirements have not been specified for January 1, 1980, the STAs on duty by that time should enhance the accident and operating experience assessment function at the plant.

DISCUSSION AND CONCLUSIONS

Public Service Electric and Gas Company (PSE&G) has committed to provide an on-shift technical advisor (STA). PSE&G will meet this commitment by increasing shift staffing to include a graduate engineer possessing specialized training. During 1980, interim STAs will serve on shift. These interim STAs will have received training in plant systems including mechanical and control systems, thermal hydraulics, core design, technical specifications, and transient and accident analysis.

During the same period of 1980, designated permanent STAs will be undergoing an approximately 35 week training program. Training will be provided in reactor theory and thermodynamics, reactor operations, health physics and chemistry, reactor systems, accident analysis, reactor simulator, and metallurgy. Fully trained, permanent STAs will be in place January 1, 1981.

The STA acts as an advisor to the Senior Shift Supervisor during nuclear plant transients. During normal operations, the STA is responsible for engineering evaluation of day-to-day plant operation from a safety point of view. This evaluation includes plant operating history, plant conditions required for maintenance and testing, adequacy of company policies on maintenance, testing and quality assurance, and implementation of administrative and operating procedures. The STA integrates industry-wide experience and "lessons learned" into procedure and training programs. The STA initiates and carries out investigation of reportable occurrences, equipment failures, design problems and operator errors and disseminates to the staff the information developed. He develops and recommends new standards for procedures and instructions.

Organizationally, the STA reports to the station Reactor Engineer; however, on a routine shift basis he is under the functional supervision of the Senior Shift Supervisor, as are all other persons on shift. Appropriate shift turnover procedures have been developed to assure transferral of information between STAs.

All STAs will complete requalification on an annual basis.

Based on our review of the material submitted, we have concluded that qualified STAs will serve on shift who will perform both an accident assessment role and an operating experience assessment function and, therefore, PSE&G has met this requirement.

I.A.1.2 Shift Supervisor Duties (2.2.1.a - NUREG-0578)

POSITION

1. The highest level of corporate management of each licensee shall issue and periodically reissue a management directive that emphasizes the primary management responsibility of the shift supervisor for safe operation of the plant under all conditions on his shift and that clearly establishes his command duties.

2. Plant procedures shall be reviewed to assure that the duties, responsibilities, and authority of the shift supervisor and control room operators are properly defined to effect the establishment of a definite line of command and clear delineation of the command decision authority of the shift supervisor in the control room relative to other plant management personnel. Particular emphasis shall be placed on the following:

a. The responsibility and authority of the shift supervisor shall be to maintain the broadest perspective of operational conditions affecting the safety of the plant as a matter of highest priority at all times when on duty in the control room. The principle shall be reinforced that the shift supervisor should not become totally involved in any single operation in times of emergency when multiple operations are required in the control room.

b. The shift supervisor, until properly relieved, shall remain in the control room at all times during accident situations to direct the activities of control room operators. Persons authorized to relieve the shift supervisor shall be specified.

c. If the shift supervisor is temporarily absent from the control room during routine operations, a lead control room operator shall be designated to assume the control room command function. These temporary duties, responsibilities, and authority shall be clearly specified.

3. Training programs for shift supervisors shall emphasize and reinforce the responsibility for safe operation and the management function the shift supervisor is to provide for assuring safety.

4. The administrative duties of the shift supervisor shall be reviewed by the senior officer of each utility responsible for plant operations. Administrative functions that detract from or are subordinate to the management responsibility for assuring the safe operation of the plant shall be delegated to other operations personnel not on duty in the control room.

DISCUSSION AND CONCLUSIONS

Public Service Electric and Gas Company (PSE&G) has issued a management directive which emphasizes the assignment of primary management responsibility to the Senior Shift Supervisor. The directive is signed by the General Manager Electric Production. It is planned that the directive will be reissued on an annual basis.

Administrative Procedure No. 5, "Operating Practices," is being revised to further clarify the responsibilities of the Senior Shift Supervisor and Shift Supervisor. This procedure will delineate the command decision authority of the Senior Shift Supervisor in the control room relative to other plant management or onshift operations personnel. Both the above referenced management directive and AP No. 5 require the Senior Shift Supervisor and Shift Supervisor to maintain, as a matter of highest priority, the broadest perspective of operational conditions affecting the safety of the facility. A supervisor who is compelled to "jump in" to prevent a misoperation or mitigate an unusual occurrence must quickly back away to survey all operating parameters so that he never loses sight of the entire operation.

A senior reactor operator (SRO) will be in the control room area whenever Salem Unit 2 is operating in Mode 1, 2, 3 or 4. The Senior Shift Supervisor or Shift Supervisor, both of whom possess a SRO license, are normally in charge. If under unique or emergency situations, senior licensed Operating Department station management personnel determine it necessary to give orders directly to control operators, they must immediately inform the Senior Shift Supervisor and all control room personnel that they have assumed responsibility for the unit. When responsibility is returned to the Senior Shift Supervisor, all shift personnel are again informed. The times of both actions are noted in the Senior Shift Supervisor's Log.

Senior Shift Supervisors attend a two part training program to develop supervisory leadership skills. The first segment of the program consists of two weeks of training in such subjects as interpersonal skills, corrective discipline, leadership styles and motivation. Approximately one year later, the Senior Shift Supervisors return for the advanced course which consists of (1) Communication and Listening; (2) Interpersonal Communication and Conflict Resolution; (3) Management and Leadership Styles; (4) Understanding and Motivating the Work Force; and (5) Coaching and Counseling.

Administrative functions that detract from or are subordinate to the management responsibility for assuring safe operation of the plant are delegated to other operations personnel not on duty in the control room or to other station personnel.

PSE&G has met the requirements of Section 2.2.1.a of NUREG-0578. Procedures have been revised to establish the authority of the Senior Shift Supervisor and Shift Supervisor and delineate a clear line of succession. Administrative duties have been reviewed and, where not safety related, reassigned to other personnel. A training program emphasizing the Senior Shift Supervisor's management function has been established.

I.A.1.3 Shift Manning

POSITION

Assure that the necessary number and availability of personnel to man the operations shifts have been designated by the licensee. Administrative procedures should be written to govern the movement of key individuals about the plant to assure that qualified individuals are readily available in the event of an abnormal or emergency situation. This should consider the recommendations on overtime in NUREG-0578. Provisions should be made for an aide to the shift supervisor to assure that, over the long term, the shift supervisor is free of routine administrative duties.

DISCUSSION AND CONCLUSION

The Public Service Electric and Gas Company's shift crew composition for the operation of Salem Units 1 and 2 will include at least two senior licensed operators, four licensed operators, four unlicensed operators and one health physics technician.

This requirement will provide the following coverage. Each unit will be supervised by a shift supervisor who is a licensed SRO on that unit, or both units may be supervised by a single individual if he is a licensed SRO on both units. The second senior operator licensed for each unit must be stationed in the control room area at all times when the unit is in operating Mode 1, 2, 3 or 4; this also could be a single individual for both units if he is licensed on both units. In addition, a reactor operator licensed for each unit must be at the controls of that unit at all times when fuel is in the reactor. Also, a relief reactor operator licensed for each unit must be available on-shift.

In addition, during fuel loading operations an additional licensed senior operator, who will only be responsible for supervising core alterations, will be present to direct those operations.

The staff's requirements for overtime restrictions include the following:

1. An individual should not be permitted to work more than 12 hours straight (not including shift turnover time).

2. There should be at least a 12-hour break between all work periods (shift turnover time is included in this 12-hour break).

3. An individual should not work more than 72 hours in any 7-day period.

4. An individual should not work more than 14 consecutive days without having two consecutive days off.

Based on the foregoing, we have concluded that the necessary number and availability of personnel to man the operating shifts will be required of the Public Service Electric and Gas Company and the limitations on overtime will be required prior to fuel loading.

I.A.3.1 Revised Scope and Criteria for Licensing Examinations

Refer to Part I, Section 13.1.1, "Training Programs" of this report, for a discussion of this item.

I.B.1 Management for Operations

I.B.1.1 Organization and Management Criteria

POSITION

Corporate management of the utility-owner of a nuclear power plant shall be sufficiently involved in the operational phase activites, including plant modifications, to assure a continual understanding of plant conditions and safety considerations. Corporate management shall establish safety standards for the operation and maintenance of the nuclear power plant. To these ends, each utility-owner shall establish an organization, parts of which shall be located onsite, to: perform independent review and audits of plant activities; provide technical support to the plant staff for maintenance, modifications, operational problems, and operational analysis, and aid in the establishment of programmatic requirements for plant activities.

The licensee shall establish an integrated organizational arrangement to provide for the overall management of nuclear power plant operations. This organization shall provide for clear management control and effective lines of authority and communication between the organizational units involved in the management, technical support, and operation of the nuclear unit.

The key characteristics of a typical organization arrangement are:

1. Integration of all necessary functional responsibilities under a single responsible head.

2. The assignment of responsibility for the safe operation of the nuclear power plant(s) to an upper level executive position.

DISCUSSION AND CONCLUSIONS

On March 5 through 7, 1980, a joint NRC team representing the Office of Nuclear Reactor Regulation and the Office of Inspection and Enforcement performed a management review of the Public Service Electric and Gas Company organization for the purpose of reviewing the management organization in regards to its capability to operate the Salem Unit 2 Nuclear Generating Station. Salem Unit 1 has been licensed for operation since August 1976.

During the team review, we found that the top corporate official dealing with nuclear power is the Senior Vice President - Energy Supply and Engineering, who is the senior corporate officer in charge of production, engineering, construction and fuel supply. This individual holds Bachelor of Science and Master of Science degrees in Engineering, an Advanced Management Degree and is a graduate of the Oak Ridge School of Reactor Technology. He has had 1 1/2 years of practical experience working at the National Reactor Testing Station in Idaho and a total of more than 24 years of experience with the Public Service Electric and Gas Company, of which more than 20 years has been in work related to the nuclear field.

Corporate management control of nuclear operations is exercised by the Senior Vice President - Energy Supply and Engineering through the Vice President - Production and the General Manager - Production, to the Manager of the Salem Nuclear Generating Station. Each of these individuals holds an engineering degree and has had at least 20 years power plant experience. The Station Manager has held an SRO license. Engineering and Construction support of nuclear operations is provided by the Vice President - Engineering and Construction who heads a department of about 550 engineers and technicians with a combined total of more than 3000 man-years of nuclear related experience.

We found that the Public Service Electric and Gas Company management under the Senior Vice President - Energy Supply and Engineering is simultaneously responsible for both fossil and nuclear operations. All of the Company's operating plants, including Salem, report directly to the General Manager - Production. This organizational arrangement could tend to dilute the attention given by corporate management to nuclear operations. However, our discussions with corporate officials revealed that heavy emphasis is placed on the nuclear operations by corporate management, with the day-to-day contact with the fossil plants handled largely as routine operations by the staffs of the Production Department and the Engineering and Construction Department.

We found that corporate level meetings are held on a virtual daily basis to assure that corporate management is aware of the status of and any problems that have developed at the Salem Nuclear Generating Station and other power plants. While there is not a documented procedure covering these meetings and formal meeting minutes are not maintained, we conclude that these daily management meetings accomplish the functions of senior management oversight desired by the staff.

We thus conclude that corporate management of Public Service Electric and Gas Company is sufficiently involved in the construction and will be sufficiently involved in the operation of Salem Unit 2 to assure a continual understanding of plant conditions and safety considerations.

We also reviewed the function and operation of the current Technical Specification offsite safety review committee, designated by Public Service Electric and Gas Company as the Nuclear Review Board. Under the Chairmanship of the General Manager - Production, the Nuclear Review Board is composed of management personnel from the Production Department, the Fuel Supply Department, and the Engineering and Construction Department. The Nuclear Review Board members have ample experience to assure a thorough understanding of nuclear plant matters. While the Technical Specifications require a meeting of the Nuclear Review Board on a quarterly basis during the initial year of reactor operation and at six-month intervals thereafter, in practice the Nuclear Review Board meets much more frequently. Minutes of the Nuclear Review Board reveal 19 meetings during 1977, 9 meetings during 1978, and 14 meetings during 1979. We conclude that the Nuclear Review Board is functioning adequately to provide independent review and audit of nuclear operations.

The review team inquired into the provisions that have been made by Public Service Electric and Gas Company for accident mitigation and recovery. We learned that there are no formal procedures now in place for accident mitigation and recovery. Some procedures are now in draft form and are being coordinated both within the Company and to interface with the offsite emergency preparedness plans of the states. The Senior Vice President - Energy Supply and Engineering has been designated as the Recovery Manager for the Company. Current plans for accident mitigation and recovery are to provide offsite support by sending a few key people to staff the near-site Emergency Operations Center, while keeping the bulk of the technical support in the Newark office where they have the data files, equipment and facilities to provide in-depth technical support to the plant as required. During our meetings on this subject, the Company representatives committed to having the accident mitigation and recovery procedures for both onsite and offsite efforts, including formalization of the offsite technical support personnel training program, completed by August 1980. Interim procedures will be in place prior to fuel loading which delineate the responsibility and authority of corporate office personnel in providing technical support. We find this commitment to be acceptable. The Office of Inspection and Enforcement will verify that these efforts are completed.

The review team also discussed the subject of training for the Public Information Manager who would assist in the offsite accident mitigation and recovery effort. The draft criteria prepared by the staff tentatively call for a minimum of six months of training in nuclear plant systems and radiation technology for this individual. The Company spokesman pointed out that this seems to be far too much specialized nuclear training to be required for this individual, particularly since they intend to have technical backup for the Public Information Manager in the event of an accident. After some discussion, the Company representatives committed to provide two months of specialized nuclear and radiation training (to be completed by August 1980) to the designated Public Information Manager and to assure that a technically knowledgeable individual would be available as back-up to the Public Information Manager. We find this commitment to be acceptable. The Office of Inspection and Enforcement will verify that this training program is completed.

The Salem plant staff organization is as shown in Figure 6.2.2 of the Salem Unit 1 Technical Specifications except that the Senior Training Supervisor and his staff have been transferred to a new offsite training center. He reports to the Manager of Methods, Department of Electric Production. The onsite training coordination function has been assigned to the Assistant to the Manager. We find this change acceptable.

I.B.1.2 Safety Engineering Group and Onsite Evaluation Capability

POSITION

Utility management shall establish a group, independent of the plant staff, but assigned onsite, to perform independent reviews of plant operational activities.

The main functions of this group will be to evaluate the technical adequacy of all procedures and changes important to safe operation of the facility, and an evaluation and assessment of the plants' operating experience and performance.

DISCUSSION AND CONCLUSION

The applicants had proposed to incorporate this independent review function within the existing Station Operating Review Committee (SORC) which has similar review responsibilities assigned by the Salem Unit 1 Technical Specifications. To improve the effectiveness of SORC in performing these reviews, the applicants were planning on having in place, by fuel loading of Salem Unit 2, four full time dedicated engineers to supplement the Committee.

Our criteria in this area are still under development. Pending final approval of criteria for size and functional capabilities of this group, and potential for redefinition of existing review groups, we requested that during the conduct of the initial startup phase, throughout low power testing, there should be at least five such personnel on site, but reporting to management offsite.

In response to this request, the applicants have committed to establish a Safety Review (Engineering) Group, independent of the station staff, but assigned on-site, to perform independent reviews of station operational activities. The group will be functioning by initial fuel load and will be composed of five persons; one supervisor and four additional persons with collective expertise in the areas of nuclear engineering, heat transfer, mechanical engineering, and instrumentation and controls. The supervisor of the group will report off-site.

On the basis of the above commitment, we conclude that the applicants meet this position. The Office of Inspection and Enforcement will verify the presence of these five people prior to fuel load.

I.B.1.4 Licensee Onsite Operating Experience Evaluation Capability

The applicants presently do not have in place formal procedures which describe a system for assessing and disseminating operating experiences to operators and other personnel involved with plant operation, both in-plant and at the company's engineering offices. Nor are formal procedures available to ensure that operating experiences are factored into the training program.

Although operating experiences from the Salem plant and some other facilities are routinely routed to operators and training personnel, the practice is informal and there is little evaluation, followup or discussion of the experiences.

The applicants are in the process of formalizing the procedures for accomplishing this task in conjunction with the Safety Engineering Group (see Section I.B.1.2) and Shift Technical Advisors (see Section I.A.1.1) and have committed to having formal procedures in place at the time of fuel loading. We find this commitment to be acceptable. The Office of Inspection and Enforcement will verify that the procedures are in place prior to fuel load.

I.B.2.2 Resident NRC Inspector

POSITION

1. The Office of Inspection and Enforcement (IE) will implement the approved resident inspector program by recruiting, training, and assigning the resident inspectors to provide a minimum of two resident inspectors at each site where there are one or two reactors.

2. IE will place a senior resident inspector at near-term operating plants by June 1980.

DISCUSSION AND CONCLUSION

Mr. Leif J. Norrholm is currently the NRC senior resident inspector at the Salem site. He has been at the site since July 1978, and has detailed knowledge of the plant design and the pertinent operating and emergency procedures. He has participated in the review and inspection of plant design, construction, safety features and pre-operational testing for Salem Unit 2 as well as for the operation of Salem Unit 1. An additional resident inspector, Mr. William M. Hill, was assigned to the site in January 1980.

Placement of NRC resident inspectors at this facility has been accomplished.

I.C Procedures

I.C.1 Short-Term Effort - Analysis and Procedure Modification (2.1.9 - NUREG-0578)

POSITION

Analyses, procedures, and training addressing the following are required:

1. Small break loss-of-coolant accidents;
2. Inadequate core cooling; and
3. Transients and accidents.

Some analysis requirements for small breaks have already been specified by the Bulletins and Orders Task Force. These should be completed. In addition, pretest calculations of some of the Loss of Fluid Test (LOFT) small break tests (scheduled to start in September 1979) shall be performed as means to verify the analyses performed in support of the small break emergency procedures and in support of an eventual long term verification of compliance with Appendix K to 10 CFR Part 50.

In the analysis of inadequate core cooling, the following conditions shall be analyzed using realistic (best-estimate) methods:

1. Low reactor coolant system inventory (two examples will be required - loss-of-coolant accident (LOCA) with forced flow, LOCA without forced flow).

2. Loss of natural circulation (due to loss of heat sink).

These calculations shall include the period of time during which inadequate core cooling is approached as well as the period of time during which inadequate core cooling exists. The calculations shall be carried out in real time far enough that all important phenomena and instrument indications are included. Each case should then be repeated taking credit for correct operator action. These additional cases will provide the basis for developing appropriate emergency procedures. These calculations should also provide the analytical basis for the design of any additional instrumentation needed to provide operators with an unambiguous indication of vessel water level and core cooling adequacy (see Section 2.1.3.b of NUREG-0578).

The analyses of transients and accidents shall include the design basis events specified in Section 15 of each Final Safety Analysis Report (FSAR). The analyses shall include a single active failure for each system called upon to function for a particular event. Consequential failures shall also be considered. Failures of the operators to perform required control manipulations shall be given consideration for permutations of the analyses. Operator actions that could cause the complete loss of function of a safety system shall also be considered. At present, these analyses need not address passive failures or multiple system failures in the short term. In the recent analysis of small break LOCAs, complete loss of auxiliary feedwater was considered. The complete loss of auxiliary feedwater may be added to the failures being considered in the analysis of transients and accidents if it is concluded that more is needed in operator training beyond the short-term actions to upgrade auxiliary feedwater system reliability. Similarly, in the long term, multiple failures and passive failures may be considered depending in part on staff review of the results of the short-term analyses.

The transient and accident analyses shall include event tree analyses, which are supplemented by computer calculations for those cases in which the system response to operator actions is unclear or these calculations could be used to provide important quantitative information not available from an event tree. For example, failure to initiate high-pressure injection could lead to core uncovery for some transients, and a computer calculation could provide information on the amount of time available for corrective action. Reactor simulators may provide some information in defining the event trees and would be useful in studying the information available to the operators. The transient and accident analyses are to be performed for the purpose of identifying appropriate and inappropriate operator actions relating to important safety considerations such as natural circulation, prevention of core uncovery, and prevention of more serious accidents.

The information derived from the preceding analyses shall be included in the plant emergency procedures and operator training. It is expected that analyses performed by the nuclear steam supply system (NSSS) vendors will be put in the form of emergency procedure guidelines and that the changes in the procedures will be implemented by each licensee or applicant.

In addition to the analyses performed by the reactor vendors, analyses of selected transients should be performed by the NRC Office of Research, using the best available computer codes, to provide the basis for comparisons with the analytical methods being used by the reactor vendors. These comparisons together with comparisons to data, including LOFT small break test data, will constitute the short-term verification effort to assure the adequacy of the analytical methods being used to generate emergency procedures.

DISCUSSION AND CONCLUSIONS

This item requires analysis, procedure guidelines, emergency procedures, and operator training related to small break loss-of-coolant accidents, inadequate core cooling, and transients and non-LOCA accidents.

Westinghouse submitted analyses for small break accidents in Topical Report WCAP-9600, "Report on Small Break Accidents for Westinghouse NSSS System", June 1979. Emergency procedure guidelines were then developed from these analyses by the Westinghouse Plant Owners Group. These guidelines were reviewed and approved by the staff in November 1979. The staff review of these analyses and guidelines was performed by the Bulletins and Orders Task Force as is documented in their report on Westinghouse reactors, "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse-Designed Operating Plants," NUREG-0611, January 1980 (Appendix IX, Section 2.2). We have reviewed the design features of the Salem Unit 2 plant and we conclude that the review and approval of the small break LOCA analyses and guidelines applies in total to the Salem Unit 2 plant.

The Salem Unit 2 small break LOCA emergency procedure is currently being reviewed by NRR and I&E as part of the Action Plan Item I.C. We require that any problem areas identified by NRR and I&E be resolved to the staff's satisfaction prior to low power testing. This is not a requirement for zero power operation.

Westinghouse submitted analyses of inadequate core cooling on October 30, 1979, "Analysis of Inadequate Core Cooling and Emergency Core Cooling Guidelines to Restore Core Cooling." The staff review of these analyses and guidelines has not been completed. Instructions on steps to be taken to restore adequate core cooling, if it should be lost, will be included in the Salem Unit 2 emergency procedures. When the Salem Unit 2 emergency procedures have been revised to include consideration of inadequate core cooling, the changes will be reviewed by the staff. We require that the inadequate core cooling guidelines and procedures be developed and implemented to the staff's satisfaction prior to low power testing. This is not a requirement for zero power operation.

The third part of this item relates to analysis, procedure guidelines, emergency procedures, and operator training for transients and accidents. The applicants have committed to providing all of the required items but have stated that it may not be possible to meet the schedule required for operating reactors, that is, analyses and guideline development due by March 31, 1980 and emergency procedures and operator training by June 30, 1980. We are continuing to discourage any delays in the established schedule. However, completion of this work is not required for the low power test program.

I.C.2 Shift Relief and Turnover Procedures (2.2.1.c - NUREG-0578)

POSITION

The licensee shall review and revise as necessary the plant procedure for shift and relief turnover to assure the following:

1. A checklist shall be provided for the oncoming and offgoing control room operators and the oncoming shift supervisor to complete and sign. The following items, as a minimum, shall be included in the checklist;

   a. Assurance that critical plant parameters are within allowable limits (parameters and allowable limits shall be listed on the checklist).

   b. Assurance of the availability and proper alignment of all systems essential to the prevention and mitigation of operational transients and accidents by a check of the control console. What to check and criteria for acceptable status shall be included on the checklist.

   c. Identification systems and components that are in a degraded mode of operation permitted by the Technical Specifications. For such systems and components, the length of time in the degraded mode shall be compared with the Technical Specifications action statement (this shall be recorded as a separate entry on the checklist).

2. Checklists or logs shall be provided for completion by the offgoing and ongoing auxiliary operators and technicians. Such checklists or logs shall include any equipment under maintenance or test that by itself could degrade a system critical to the prevention and mitigation of operational transients and accidents or initiate an operational transient (what to check and criteria for acceptable status shall be included on the checklist); and

3. A system shall be established to evaluate the effectiveness of the shift and relief turnover procedures (for example, periodic independent verification of system alignments).

DISCUSSION AND CONCLUSIONS

Shift relief turnover requirements are described in AP-5 "Operating Practices," Operating Memo 20, and in the Operations Department Manual (ODM). These requirements provide assurance that the on-coming shift will possess adequate knowledge of critical plant status information and system availability. Operations Logs and Checklists have been developed. The ODM describes the logs and checklists used by Shift Supervisors, Control Operators, Equipment Operators and Utility Operators and the requirements for signature by both the on-coming and off-going shifts.

Completed logs and checklists are reviewed as soon as possible, usually the next work day, by the Operating Engineers or, when required, the Senior Operating Staff Supervisor.

We have reviewed PSE&G's implementation of this requirement as well as the logs and checklists to be filled out by the off-going and on-coming shifts. We conclude that an adequate exchange of information will take place during shift turnover and that the system used receives management evaluation. PSE&G has met this requirement.

I.C.3 Shift Personnel Responsibilities (2.2.1.a - NUREG-0578)

This item is included with Section I.A.1.2 of Part II to this report.

I.C.4 Control Room Access (2.2.2.a - NUREG-0578)

POSITION

The licensee shall make provisions for limiting access to the control room to those individuals responsible for the direct operation of the nuclear power plant (e.g., operations supervisor, shift supervisor, and control room operators), to technical advisors who may be requested or required to support the operation, and the predesignated NRC personnel. Provisions shall include the following:

1. Develop and implement an administrative procedure that establishes the authority and responsibility of the person in charge of the control room to limit access; and

2. Develop and implement procedures that establish a clear line of authority and responsibility in the control room in the event of an emergency. The line of succession for the person in charge of the control room shall be established and limited to persons possessing a current senior reactor operator's license. The plan shall clearly define the lines of communication and authority for plant management personnel not in direct command of operations, including those who report to stations outside of the control room.

DISCUSSION AND CONCLUSIONS

Salem Nuclear Generating Station Administrative Procedure No. 5 (AP-5), "Operating Practices," presently addresses control room access. AP-5 is being revised to include specific individual authority and responsibility related to controlling personnel access during normal and accident conditions.

During normal operating conditions, individuals are permitted entry into the control room only when specific duties require such entry. The Senior Shift Supervisor and Shift Supervisor are authorized to refuse entry or to direct personnel to leave the control room if their presence interferes with operations or may compromise plant safety.

During emergency conditions, access to the control room will be limited to those individuals responsible for the direct operation of the facility, to technical advisors required to support operation, to NRC Resident Inspectors, and to personnel specifically requested by the Senior Shift Supervisor or Shift Supervisor. During emergency conditions, control room access will be limited to no more than 15 authorized personnel in the control room at any time. If requested, the security force will assist in enforcement of the control room access restriction.

On-coming operating shift personnel reporting to the station during an emergency condition will report to the Onsite Operations Support Center, notify the Senior Shift Supervisor or Shift Supervisor of their presence, and await further instructions.

During routine or emergency conditions, the expected chain of command will be through the Senior Shift Supervisor to the Shift Supervisor to the licensed Control Operators.

During certain unique situations, senior licensed Operating Department station management personnel (for example, Chief Engineer - SRO or Operating Engineer - SRO) may determine it necessary to give orders directly to the Control Operators. If this occurs, all personnel in the control room will be notified that they have assumed command and responsibility for the unit and this information is logged.

Individuals who do not possess a valid SRO license, including members of station management, may not relieve the Senior Shift Supervisor or Shift Supervisor, nor may they direct the licensed activities of licensed operators.

Lines of communication and authority for plant management personnel not in direct command of operations, including those who report to stations outside of the control room, are described in the revised Emergency Plan Manual and are acceptable.

We have reviewed the applicable administrative procedure, the planned revision to the procedure and the revised Emergency Plan Manual. We conclude that PSE&G has met this requirement.

I.C.5 Licensee Dissemination of Operating Experiences

See Section 1.B.1.4 of Part II to this report.

I.C.7 NSSS Vendor Review of Low Power Test Procedures

All of the applicants' startup test procedures, from core load through power ascension, are being reviewed by the vendor, Westinghouse. This review, as well as vendor review of test results, will continue and will include the special test program. These reviews are documented in the applicable procedures.

In addition, the NSSS vendor will provide shift coverage during active testing periods for the low power physics tests and the special test program.

I.G Training During Low Power Testing

Introduction

In a letter dated December 3, 1979 to Joseph Hendrie (NRC), S. David Freeman, Chairman of the Board of TVA, proposed "pursuing certain limited activities in the case of those power plants where construction has been completed during the Commission's pause..." One of the activities proposed was a series of natural circulation tests to be performed at Unit 1 of the Sequoyah Nuclear plant at power levels up to five percent of normal full power. By letter to Olan Parr (NRC) dated February 8, 1980, Mr. R. L. Mittl of Public Service Electric and Gas Company (PSE&G) proposed performing similar tests on Salem Unit 2. The proposed test program was further described in a letter, dated March 31, 1980.

The proposed low power test program for Salem Unit 2 was reviewed by the staff using the following five criteria:

1. The tests should provide meaningful technical information beyond that obtained in the normal startup test program.

2. The tests should provide supplemental operator training.

3. The tests should not pose an undue risk to the public.

4. The risk of damage to the nuclear plant during the test program should be low.

5. The radiation levels that will exist after the low power test program is completed (including that from crud deposits) must not preclude implementation of requirements stemming from the NRR Lessons Learned Task Force, Kemeny Commission, Rogovin Commission or Task Action Plan.

The low power test program proposed by PSE&G consists of nine tests, seven of which involve natural circulation in the reactor coolant system at low power conditions, but at normal, or nearly normal, operating pressures and temperatures. The test program is nearly identical to the program proposed to be performed on Sequoyah Unit 1 and reviewed by the NRC staff. The only significant difference between the two proposed programs is that the simulated loss of all onsite and offsite power (test 6 below), will be performed using heat from the reactor coolant system pumps to simulate decay heat; the test to be performed on Sequoyah Unit 1 will use fission heat to simulate decay heat.

The specific tests proposed are:

1. Natural circulation test;

2. Natural circulation with simulated loss of offsite ac power;

3. Natural circulation with loss of pressurizer heaters;

4. Effect of secondary side isolation on natural circulation;

5. Natural circulation at reduced pressure;

6. Cooldown capability of the charging and letdown system;

7. Simulated loss of all onsite and offsite ac power;

8. Establishment of natural circulation from stagnant conditions; and

9. Forced circulation cooldown (part A) and boron mixing and cooldown (part B).

The tests will not necessarily be performed in this order. In general the test program will progress from relatively simple tests to those that are more complex. Members of the NRC staff will observe the performance of selected tests.

STAFF EVALUATION

The staff is in the process of evaluating the low power test program proposed by PSE&G. The criteria listed above are being used as the basis of the evaluation. The status of the staff's review is described below for each of the criteria.

A. CRITERION 1

Criterion 1 states that the tests should provide meaningful technical information beyond that obtained during the normal test program. By meaningful we mean information that adds to the understanding of the capabilities of a plant to remove heat from the reactor either by natural convection circulation of reactor coolant or by other heat transfer mechanisms considered in the analyses of small loss-of-coolant accidents. Although natural circulation tests have been performed on many reactors, they have not been done under degraded plant conditions, such as loss of electrical power or isolation of the secondary side of a steam generator.

The staff has reviewed each of the tests proposed by PSE&G relative to Criterion 1. We have concluded that the test program will provide meaningful technical information.

The earlier tests in the series are only expected to confirm that natural circulation can be obtained, and to develop the techniques needed to simulate decay heat using fission heat. As the program proceeds to the more complex tests, meaningful information is expected to be obtained. This is especially true for the test in which loss of all alternating current electric power, both onsite and offsite, is simulated. This test is expected to demonstrate a design capability that has never previously been experimentally confirmed in a commercial nuclear power plant. Similar tests are planned to be performed on Sequoyah Unit 1 and North Anna Unit 2. Other tests that are expected to provide significant technical information are those that demonstrate that natural circulation can be established from stagnant conditions and that determine the degree of boron mixing that can be obtained under natural circulation conditions.

It should be noted that all of the natural circulation tests proposed by PSE&G will be single phase, liquid tests. That is, the tests will be initiated and conducted with the reactor coolant subcooled. Thus, the tests will not be representative of the two-phase conditions that might exist following an accident. PSE&G opposes two-phase testing because they believe that the potential risk of damage to the plant outweighs the benefits to be gained. Despite the lack of two-phase tests in the proposed test program, the staff concludes that the test program will provide meaningful information and is expected to confirm the ability of the plant to perform as designed in areas that have not been previously demonstrated in commercial, light-water nuclear power plants.

B. CRITERION 2

Criterion 2 states that the tests should provide supplemental operator training. In regard to the training objectives of the test program, PSE&G plans to conduct a sufficient number of repetitions of tests 1 through 6 so that each licensed operator will participate in at least one test and observe two others. Tests 7 through 9 will run several times so that each operating crew will have an opportunity to gain "hands-on" experience for each of these tests. Some of the training that will be obtained during low power testing could also be provided by simulator training. However, simulator training is generally limited to operations that take place in the control room. The performance of the test program will aid in the check-out of procedures for those operations conducted outside the control room, and provide training in those operations. Therefore, the staff concludes that the proposed test program will provide valuable training not otherwise available for the Salem operating crews.

As noted above, all of the natural circulation tests proposed to be performed on Salem Unit 2 will be single phase liquid tests. Unless the licensed operators are given additional training, they could be misled into believing that the single-phase natural circulation conditions they experience in performing the test program would be representative of the two-phase conditions they may encounter following an accident.

PSE&G recognizes that the special natural circulation tests proposed may not be representative of the two-phase flow conditions that might exist following an accident. They have stated that they will ensure that plant operators involved in the special tests recognize the differences in plant response between subcooled and two-phase reactor coolant flow conditions by conducting formal briefings with each licensed shift crew prior to commencement of the special test. By letter, dated March 28, 1980, we have provided all applicants and licensees, including PSE&G, our training requirements for two-phase flow conditions.

C. CRITERION 3

Criterion 3 requires that the tests should not pose an undue risk to the public. PSE&G has not submitted, for staff review, the safety analyses that demonstrate that Criterion 3 will be satisfied. PSE&G intends to submit these analyses at least four weeks prior to the scheduled start of the low power test program. Since the proposed test program will be performed at power levels of five percent or less, the decay heat in the event of a reactor trip or an accident will be about comparable to heat losses at normal reactor coolant system operating temperature. Therefore, we do not anticipate that the safety analysis to be prepared by PSE&G will uncover any significant safety problems. However, review of these safety analyses by the staff along with the supporting safety evaluation report, will be required prior to beginning the test program.

We will require that PSE&G prepare, and submit for staff review, any special procedures required for the low power test program. These special procedures should clearly define any special technical specifications needed to perform each test, including any changes to the safety system setpoints. The staff review of the special test procedures will concentrate on the overall approach proposed by PSE&G, not the details of valve lineup and the designation of instruments to be used to record data.

In addition to individual procedures for each low power test, the staff will require that some type of lead or master document be prepared by PSE&G. This document should outline the entire test program, defining the sequence in which the individual tests will be performed. For each individual test, the master document should specify which conditions should be established or maintained, and what orders or instructions apply during the period the test is being performed, including the applicable emergency procedures if-limits are exceeded. At the conclusion of each individual test, the master document should specify that normal technical specifications and licensed plant conditions, including safety system settings, apply. The master document should also specify that the normal plant administrative procedures will be followed when tests are being conducted so there will be no doubt that the licensed senior operator has the authority and responsibility to direct the licensed operators in accordance with 10 CFR 55.4(e).

Also, PSE&G should thoroughly review the special test procedures and test exemptions relative to the normal operating procedures and technical specifications to assure that there are no ambiguities that will rise during testing.

D. <u>CRITERION 4</u>

Criterion 4 states that the risk of damage to the nuclear power plant during the test program should be low. In this regard, PSE&G has not proposed any tests that it feels represent more than a minimal risk to Salem Unit 2. The staff concurs in this matter. This is the major reason it has not proposed any natural circulation tests involving two-phase conditions.

E. CRITERION 5

Criterion 5 states that the radiation levels that will exist after the low power test program is completed (including that from crud deposits) must not preclude implementation of requirements stemming from the TMI-2 accident. PSE&G has stated that they will evaluate the radiation levels that will exist at the completion of the low power test program. This evaluation will be performed prior to the initiation of the program. The objective of the evaluation is to assure that the radiation levels created by the low power testing will not prevent implementation of any requirements for physical alterations dictated by the Lessons Learned Task Force, Kemeny Commission, Rogovin Commission, or Task Action Plan as presently understood.

ADDITIONAL TESTS

The staff has requested that PSE&G also obtain some baseline data regarding differential pressure across the elbow pressure taps in each reactor coolant loop for various pump combinations. PSE&G has agreed to perform such tests.

These tests will be conducted with the core installed, but all control rod assemblies inserted. The reactor coolant system will be at about normal operating temperature and pressure. The tests will be performed with one pump, two pumps, and three pumps operating. The differential pressure data will be obtained in all four loops; that is, the loops with flow in the normal direction and the loops having flow in the reverse direction. Pump data such as motor current will also be recorded.

The purpose of the tests is to provide baseline data for an undamaged core. In the event that there is an accident sometime in the future involving core damage, similar data could be obtained and compared to the baseline data to infer the extent of the core damage.

II SITING AND DESIGN

II.B.4 Degraded Core - Training

POSITION

The staff requires that the applicants develop a program to ensure that all operating personnel are training in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged. The training program shall include the following topics.

A. Incore Instrumentation

1. Use of fixed or movable incore detectors to determine extent of core damage and geometry changes.

2. Use of thermocouples in determining peak temperatures; methods for extended range readings; methods for direct readings at terminal junctions.

B. Excore Nuclear Instrumentation (NIS)

1. Use of NIS for determination of void formation; void location basis for NIS response as a function of core temperatures and density changes.

C. Vital Instrumentation

1. Instrumentation response in an accident environment; failure sequence (time to failure, method of failure); indication reliability (actual vs indicated level).

2. Alternative methods for measuring flows, pressures, levels, and temperatures.

   a. Determination of pressurizer level if all level transmitters fail.

   b. Determination of letdown flow with a clogged filter (low flow).

c. Determination of other reactor coolant system parameters if the primary method of measurement has failed.

D. Primary Chemistry

1. Expected chemistry results with severe core damage; consequences of transferring small quantities of liquid outside containment; importance of using leak tight systems.

2. Expected isotopic breakdown for core damage; for clad damage.

3. Corrosion effects of extended immersion in primary water; time to failure.

E. Radiation Monitoring

1. Response of process and area monitors to severe damages; behavior of detectors when saturated; method for detecting radiation readings by direct measurement at detector output (overanged detector); expected accuracy of detectors at different locations; use of detectors to determine extent of core damage.

2. Methods of determining dose rate inside containment from measurements taken outside containment.

F. Gas Generation

1. Methods of H generation during an accident; other sources of gas (Xe, Ke); techniques for venting or disposal of non-condensibles.

2. H flammability and explosive limit; sources of 0 in containment or reactor coolant system.

DISCUSSION AND CONCLUSIONS

We recently transmitted to the applicants our requirements regarding training to control or mitigate an accident in which the core is severely damaged. The applicants have committed to such a program. Therefore, we consider this matter resolved for the low power testing program.

II.D.2 Relief and Safety Valve Test (2.1.2 - NUREG-0578)

POSITION

Pressurized water reactor and boiling water reactor licensees and applicants shall conduct testing to qualify the reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.

CLARIFICATION

1. Expected operating conditions can be determined through the use of analysis of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70.

2. This testing is intended to demonstrate valve operability under various flow conditions, that is, the ability of the valve to open and shut under the various flow conditions should be demonstrated.

3. Not all valves on all plants are required to be tested. The valve testing may be conducted on a prototypical basis.

4. The effect of piping on valve operability should be included in the test conditions. Not every piping configuration is required to be tested, but the configurations that are tested should produce the appropriate feedback effects as seen by the relief or safety valve.

5. Test data should include data that would permit an evaluation of discharge piping and supports if those components are not tested directly.

6. A description of the test program and the schedule for testing should be submitted by January 1, 1980.

7. Testing shall be complete by July 1, 1981.

DISCUSSION AND CONCLUSIONS

We require that the Public Service Electric and Gas Company carry out a testing program to qualify the relief and safety valves under expected operating conditions for design basis transients and accidents as provided in NUREG-0578, Section 2.1.2, and as clarified in NRC letter to operating license applicants dated November 9, 1979. Accordingly, the low power operating license will be conditioned.

The Public Service Electric and Gas Company has stated that they are actively pursuing a joint effort with other members of the utility industry which will develop requirements for a generic test facility and program for RCS relief and safety valve prototypical testing. This involves subscription to and participation in a program developed and managed by the Electric Power Research Institute (EPRI). The initial result of that joint industry effort (i.e., the EPRI "Program Plan for the Performance Verification of PWR Safety/Relief Valves and Systems") was presented to and discussed with representatives of the NRC staff at a meeting with EPRI personnel on December 17, 1979.

The staff will perform a detailed review of the generic program proposed by EPRI. On the basis of our preliminary discussions to date with EPRI regarding the feasibility of meeting the clarified valve testing requirements of NUREG-0578 (including discussions at the December 17 meeting), and on the basis of PSE&G's assurance that the proposed EPRI program will be applicable to the Salem Unit 2 design and consistent with the NRC position in this regard, we believe that there is adequate assurance at this point that the NUREG-0578 requirement regarding performance verification of RCS relief and safety valves will be met satisfactorily for Salem Unit 2. We conclude that, pending satisfactory results from the ongoing test program, this requirement places no restrictions on Salem Unit 2 operation through full power.

In establishing these test requirements as part of NUREG-0578, the staff concluded that the extended time for completion of the qualification testing was appropriate since this testing is considered to be confirmatory in nature.

II.D.5 Relief and Safety Valve Position (2.1.3.a - NUREG-0578)

POSITION

Reactor system relief and safety valves shall be provided with a positive indication in the control room derived from a reliable valve position detection device or a reliable indication of flow in the discharge pipe.

CLARIFICATION

1. The basic requirement is to provide the operator with unambiguous indication of valve position (open or closed) so that appropriate operator actions can be taken.

2. The valve position should be indicated in the control room. An alarm should be provided in conjunction with this indication.

3. The valve position indication may be safety grade. If the position indication is not safety grade, a reliable single channel direct indication powered from a vital instrument bus may be provided if backup methods of determining valve position are available and are discussed in the emergency procedures as an aid to operator diagnosis and action.

4. The valve position indication should be seismically qualified consistent with the component or system to which it is attached. If the seismic qualification requirements cannot be met feasibly by January 1, 1980, a justification should be provided for less than seismic qualification and a schedule should be submitted for upgrade to the required seismic qualification.

5. The position indication should be qualified for its appropriate environment (any transient or accident which would cause the relief or safety valve to lift). If the environmental qualification program for this position indication will not be completed by January 1, 1980, a proposed schedule for completion of the environment qualification program should be provided.

DISCUSSION AND CONCLUSIONS

Two power-operated relief valves (PORV) and three safety valves, connected to the top of the pressurizer are provided in the Salem Unit 2 design to protect against overpressurization. Positive indication of PORV position is obtained by a direct, stem-mounted indicator which mechanically activates limit switches at the full-open and full-closed valve stem positions (single channel for each PORV).

These switches are seismically and environmentally qualified and provide an alarm in the control room if a PORV is not fully closed. The switches are powered from a vital bus.

PSE&G has installed limit switches in the bonnet of each safety valve to alarm in the control room if the safety valve is not fully closed. The switches are seismically and environmentally qualified and are powered from a vital bus. An improved switch capable of indicating open, closed, and an intermediate position will be installed by June 1, 1980.

The described design incorporates only a single channel of positive position indication for each PORV and safety valve. In accordance with the NRC position and clarification, therefore, PSE&G has described backup methods of determining valve positions. These include temperature sensors downstream of each valve, pressurizer relief tank temperature/pressure/ level indicators and pressurizer high pressure sensors. These sensors provide indication alarms in the main control room and are reflected in the plant operating procedures.

On the basis of PSE&G's submittals to NRC describing these new systems, discussions with PSE&G's engineering and operating staff representatives, and an inspection tour of the Salem Unit 2 facility, the PSE&G approach to providing positive pressurizer relief and safety valve position indication, by use of limit switches on the PORVs and safety valves, is acceptable.

II.E.1.2 Auxiliary Feedwater Initiation and Indication

Auxiliary Feedwater Initiation (2.1.7.a - NUREG-0578)

POSITION

Consistent with satisfying the requirements of General Design Criterion 20 of Appendix A to 10 CFR Part 50 with respect to the timely initiation of the auxiliary feedwater system, the following requirements shall be implemented in the short term:

1. The design shall provide for the automatic initiation of the auxiliary feedwater system.

2. The automatic initiation signals and circuits shall be designed so that a single failure will not result in the loss of auxiliary feedwater system function.

3. Testability of the initiating signals and circuits shall be a feature of the design.

4. The initiating signals and circuits shall be powered from the emergency buses.

5. Manual capability to initiate the auxiliary feedwater system from the control room shall be retained and shall be implemented so that a single failure in the manual circuits will not result in the loss of system function.

6. The a-c motor driven pumps and valves in the auxiliary feedwater system shall be included in the automatic actuation (simultaneous and/or sequential) of the loads onto the emergency buses.

7. The automatic initiating signals and circuits shall be designed so that their failure will not result in the loss of manual capability to initiate the auxiliary feedwater system from the control room.

In the long term, the automatic initiation signals and circuits shall be upgraded in accordance with safety grade requirements.

CLARIFICATION

Control Grade (Short-Term)

1. Provide automatic/manual initiation of AFWS.

2. Testability of the initiating signals and circuits is required.

3. Initiating signals and circuits shall be powered from the emergency buses.

4. Necessary pumps and valves shall be included in the automatic sequence of the loads to the emergency buses. Verify that the addition of these loads does not compromise the emergency diesel generating capacity.

5. Failure in the automatic circuits shall not result in the loss of manual capability to initiate the AFWS from the control room.

6. Other Considerations

   a. For those designs where instrument air is needed for operation, the electric power supply requirement should be capable of being manually connected to emergency power sources.

DISCUSSION AND CONCLUSIONS

The auxiliary feedwater (AFW) system for Salem Unit 2 was designed as a safety-related system, aside and apart from any TMI-related requirements imposed subsequently by NRC. Consistent with that design intent, and as described in the applicants' submittals to NRC and in discussions with the applicants in connection with this NUREG-0578 position, the AFW initiating circuitry for Salem Unit 2 incorporates both automatic and manual system start capability, including manual initiation of the system from the main control room. Manual initiation capability is provided independent of automatic initiation, and the design of the automatic initiation circuitry is such that a single-failure cannot result in total loss of the AFW system function. Further, the Salem Unit 2 design incorporates on-line testability, and the system is powered from reliable emergency buses as specified in NUREG-0578 (including automatic actuation of a-c motor driven pumps and valve loads onto the emergency buses).

The Salem Unit 2 AFW initiation circuitry design meets NUREG-0578 short-term requirements.

Auxiliary Feedwater Indication (2.1.7.b - NUREG-0578)

POSITION

Consistent with satisfying the requirements set forth in General Design Criterion 13 to provide the capability in the control room to ascertain the actual performance of the AFWS when it is called to perform its intended function, the following requirements shall be implemented:

1. Safety grade indication of auxiliary feedwater flow to each steam generator shall be provided in the control room.

2. The auxiliary feedwater flow instrument channels shall be powered from the emergency buses consistent with satisfying the emergency power diversity requirements of the auxiliary feedwater system set forth in Auxiliary Systems Branch Technical Position 10-1 of the Standard Review Plan, Section 10.4.9.

CLARIFICATION

A. Control Grade (Short-Term)

   1. Auxiliary feedwater flow indication to each steam generator shall satisfy the single failure criterion.

   2. Testability of the auxiliary feedwater flow indication channels shall be a feature of the design.

   3. Auxiliary feedwater flow instrument channels shall be powered from the vital instrument buses.

B. Safety Grade (Long-Term)

   1. Auxiliary feedwater flow indication to each steam generator shall satisfy safety grade requirements.

C. Other

   1. For the short-term, the flow indication channels should by themselves satisfy the single failure criterion for each steam generator. As a fall-back position, one auxiliary feedwater flow channel may be backed up by a steam generator level channel.

   2. Each auxiliary feedwater channel should provide an indication of feed flow with an accuracy on the order of ±10 percent.

DISCUSSION AND CONCLUSIONS

Auxiliary feedwater (AFW) flow indication for Salem Unit 2 is provided by a single flow indicating element (channel) in the individual AFW feed lines to each of the four steam generators. These flow channels are powered from the vital buses (battery-backed).

The applicants have noted that the direct flow indication arrangement provided is backed by safety grade steam generator water level indication. Taken together then, the combined (direct and indirect) AFW flow indication capability does satisfy the single failure criterion. Further, the direct flow indication channels provide indication with an accuracy of approximately ±two percent; and testability of all channels is a feature of design.

The direct AFW flow indication arrangements provided for the Salem Unit 2 satisfy the "control grade" requirements specified in the NUREG-0578 position and clarifications and, therefore, are acceptable.

II.E.4.1 Containment Penetrations (2.1.5.a NUREG-0578)

POSITION

Plants using external recombiners or purge systems for post-accident combustible gas control of the containment atmosphere should provide containment isolation systems for external recombiner or purge systems that are dedicated to that service only, that satisfy the redundancy and single failure requirements of General Design Criteria 54 and 56 of Appendix A to 10 CFR Part 50, and that are sized to satisfy the flow requirements of the recombiner or purge system.

CLARIFICATION

1. This requirement is only applicable to those plants whose licensing basis includes requirements for external recombiners or purge systems for post-accident combustible gas control of the containment atmosphere.

2. An acceptable alternative to the dedicated penetration is a combined design that is single-failure proof for containment isolation purposes and single-failure proof for operation of the recombiner or purge system.

3. The dedicated penetration or the combined single-failure proof alternative should be sized such that the flow requirements for the use of the recombiner or purge system are satisfied.

4. Components necessitated by this requirement should be safety grade.

5. A description of required design changes and a schedule for accomplishing these changes should be provided by January 1, 1980. Design changes should be completed by January 1, 1981.

DISCUSSION AND CONCLUSIONS

Salem Unit 2 does not use external recombiners or purge systems for post-accident combustible gas control. The Salem Unit 2 design has a manually actuated ESF recombiner system inside containment which is redundant and fully qualified.

This requirement is not applicable to Salem Unit 2.

II.F.1 Additional Accident Monitoring Instrumentation (2.1.8.b - NUREG-0578)

POSITION

The requirements associated with this recommendation should be considered as advanced implementation of certain requirements to be included in a revision to Regulatory Guide 1.97, "Instrumentation to Follow the Course of an Accident," which has already been initiated, and in other Regulatory Guides, which will be promulgated in the near-term.

1. Noble gas effluent monitors shall be installed with an extended range designed to function during accident conditions as well as during normal operating conditions; multiple monitors are considered to be necessary to cover the ranges of interest.

   a. Noble gas effluent monitors with an upper range capacity of 10^5m Ci/cc (Xe-133) are considered to be practical and should be installed in all operating plants.

   b. Noble gas effluent monitoring shall be provided for the total range of concentration extending from normal condition (ALARA) concentrations to a maximum of 10^5m Ci/cc (Xe-133). Multiple monitors are considered to be necessary to cover the ranges of interest. The range capacity of individual monitors should overlap by a factor of 10.

2. Since iodine gaseous effluent monitors for the accident condition are not considered to be practical at this time, capability for effluent monitoring of radioiodines for the accident condition shall be provided with sampling conducted by adsorption on charcoal or other media, followed by onsite laboratory analysis.

3. In-containment radiation level monitors with a maximum range of 10^8 rad/hr shall be installed. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be designed and qualified to function in an accident environment.

CLARIFICATION

The January 1, 1980 requirements were specifically added by the Commission and were not included in NUREG-0578. The purpose of the interim January 1, 1980 requirements is to assure that licensees have methods of quantifying radioactivity releases should the existing effluent instrumentation go off-scale.

1. Radiological Noble Gas Effluent Monitors

A. January 1, 1980 Requirements

Until final implementation in January 1, 1981, all operating reactors must provide, by January 1, 1980, an interim method for quantifying high-level releases which meets the requirements of Table 2.1.8.b.1. This method is to serve only as a provisional fix with the more detailed, exact methods to follow. Methods are to be developed to quantify release rates of up to 10,000 Ci/sec for noble gases from all potential release points (e.g., auxiliary building, radwaste building, fuel handling building, reactor building, waste gas decay tank releases, main condenser air ejector, BWR main condenser vacuum pump exhaust, PWR steam safety valves and atmosphere steam dump valves and BWR turbine buildings) and any other areas that communicate directly with systems which may contain primary coolant or containment gases (e.g., letdown and emergency core cooling systems and external recombiners). Measurements/analysis capabilities of the effluents at the final release point (e.g., stack) should be such that measurements of individual sources which contribute to a common release point may not be necessary. For assessing radioiodine and particulate releases, special procedures must be developed for the removal and analysis of the radioiodine/particulate sampling media (i.e., charcoal canister/filter paper). Existing sampling locations are expected to be adequate; however, special procedures for retrieval and analysis of the sampling media under accident conditions (e.g., high air and surface contamination and direct radiation levels) are needed.

It is intended that the monitoring capabilities called for in the interim can be accomplished with existing instrumentation or readily available instrumentation. For noble gases, modifications to existing monitoring systems, such as the use of portable high-range survey instruments, set in shielded collimators so that they "see" small sections of sampling lines, is an acceptable method for meeting the intent of this requirement. Conversion of the measured dose rate (mr/hr) into concentration (μCi/cc) can be performed

TABLE 2.1.8.b.1

INTERIM PROCEDURES FOR QUANTIFYING

HIGH-LEVEL ACCIDENTAL RADIOACTIVITY RELEASES

Licensees are to implement procedures for estimating noble gas and radioiodine release rates if the existing effluent instrumentation goes off-scale.

Examples of major elements of a highly radioactive effluent release special procedures (noble gas).

- Preselected location to measure radiation from the exhaust air, e.g., exhaust duct or sample line.
- Provide shielding to minimize background interference.
- Use of an installed monitor (preferable) or dedicated portable monitor (acceptable) to measure the radiation.
- Predetermined calculational method to convert the radiation level to radioactive effluent release rate.

using standard volume source calculations. A method must be developed with sufficient accuracy to quantify the iodine releases in the presence of high background radiation from noble gases collected on charcoal filters. Seismically qualified equipment and equipment meeting IEEE 279 is not required.

The licensee shall provide the following information on his methods to quantify gaseous releases of radioactivity from the plant during an accident.

1. Noble Gas Effluents

   a. System/method description, including:

      i. Instrumentation to be used including range or sensitivity, energy dependence, and calibration frequency and technique.

      ii. Monitoring/sampling locations, including methods to assure representative measurements and background radiation correction.

      iii. A description of method to be employed to facilitate access to radiation readings. For January 1, 1980, control room readout is preferred; however, if impractical, in situ readings by an individual with verbal communication with the control room is acceptable based on iv., below.

      iv. Capability to obtain radiation readings at least every 15 minutes during an accident.

      v. Source of power to be used. If normal ac power is used, an alternate backup power supply should be provided. If dc power is used, the source should be capable of providing continuous readout for 7 consecutive days.

   b. Procedures for conducting all aspects of the measurement/analysis, including:

      i. Procedures for minimizing occupational exposures.

      ii. Calculational methods for converting instrument readings to release rates based on exhaust air flow and taking into consideration radionuclide spectrum distribution as a function of time after shutdown.

iii. Procedures for dissemination of information.

iv. Procedures for calibration.

2. Radioiodine and Particulate Effluents

A. For January 1, 1980 the licensee should provide the following:

1. System/method description, including:

a. Instrumentation to be used for analysis of the sampling media with discussion on methods used to correct for potentially interfering background levels of radioactivity.

b. Monitoring/sampling location.

c. Method to be used for retrieval and handling of sampling media to minimize occupational exposure.

d. Method to be used for data analysis of individual radionuclides in the presence of high levels of radioactive noble gases.

e. If normal ac power is used for sampling collection and analysis equipment, an alternate backup power supply should be provided. If dc power is used, the source should be capable of providing continuous readout for 7 consecutive days.

2. Procedures for conducting all aspects of the measurement analysis, including:

a. Minimizing occupational exposure.

b. Calculational methods for determining release rates.

c. Procedures for dissemination of information.

d. Calibration frequency and technique.

DISCUSSION AND CONCLUSIONS

Monitors for radioactive effluents currently installed at Salem Unit 2 are designed to detect and measure releases associated with normal reactor operations and anticipated operational occurrences. Such monitors are required to operate in radioactivity concentrations approaching the minimum concentration detectable with "state-of-the-art" sample collection and detection methods. These monitors comply with the criteria of Regulatory Guide 1.21 with respect to releases from normal operations and anticipated operational occurrences.

Radioactive gaseous effluent monitors designed to operate under conditions of normal operation and anticipated operational occurrences do not have sufficient dynamic range to function under release conditions associated with certain types of accident. General Design Criterion 64 of Appendix A to 10 CFR Part 50 requires that effluent discharge paths be monitored for radioactivity that may be released from postulated accidents.

The potential gaseous effluent release points at Salem Unit 2, consist of the process vent, ventilation stacks A and B, and the main steam safety valve discharge pipes.

As an interim measure for the determination of high level noble gas releases, Salem Unit 2, will use gamma radiation area monitors located near the various effluent discharge pipes, vents, or stacks to measure the gamma radiation produced during passage of noble gases during accidents. The applicants have provided procedures relating the observed monitor readings, calculated noble gas concentrations in the discharge path for a given monitor reading and the observed air volume flow rate to provide an estimate of gross radioactivity release rates. The applicants' procedures have been reviewed and were found to be acceptable.

Interim procedures for monitoring high level radioiodine and radioactive particulates in gaseous effluents have been provided to the staff. The applicants' procedures have been reviewed and were found to be acceptable.

The equipment and procedures described by the applicant meet our position in NUREG-0578 and are, therefore, acceptable.

II.F.2 Inadequate Core Cooling Instruments (2.1.3.b - NUREG-0578)

SUBCOOLING METER

POSITION

Licensees shall develop procedures to be used by the operator to recognize inadequate core cooling with currently available instrumentation. The licensee shall provide a description of the existing instrumentation for the operators to use to recognize these conditions. A detailed description of the analyses needed to form the basis for operator training and procedure development shall be provided pursuant to another short-term requirement, "Analysis of Off-Normal Conditions, Including Natural Circulation" (See Section 2.1.9 of NUREG-0578).

In addition, each PWR shall install a primary coolant saturation meter to provide on-line indication of coolant saturation condition. Operator instruction as to use of this meter shall include consideration that is not to be used exclusive of other related plant parameters.

CLARIFICATION

1. The analysis and procedures addressed in paragraph one above will be reviewed and should be submitted to the NRC "Bulletins and Orders Task Force" for review.

2. The purpose of the subcooling meter is to provide a continuous indication of margin to saturated conditions. This is an important diagnostic tool for the reactor operators.

3. Redundant safety grade temperature input from each hot leg (or use of multiple core exit T/C's) are required.

4. Redundant safety grade system pressure measures should be provided.

5. Continuous display of the primary coolant saturation conditions should be provided.

6. Each PWR should have: (A) Safety grade calculational devices and display (minimum of two meters) or (B) a highly reliable single channel environmentally qualified, and testable system plus a backup procedure for use of steam tables. If the plant computer is to be used, its availability must be documented.

7. In the long term, the instrumentation qualifications must be required to be upgraded to meet the requirements of Regulatory Guide 1.97 (Instrumentation for Light Water Cooled Nuclear Plants to Assess Plant Conditions During and Following an Accident) which is under development.

8. In all cases appropriate steps (electrical, isolation, etc.) must be taken to assure that the addition of the subcooling meter does not adversely impact the reactor protection or engineered safety features systems.

9. The attachment (shown below) provides a definition of information required on the subcooling meter.

INFORMATION REQUIRED ON THE SUBCOOLING METER

Display

Information Displayed (T-Tsat, Tsat, Press, etc.) ________
Display Type (Analog, Digital, CRT) ________
Continuous or on Demand ________
Single or Redundant Display ________
Location of Display ________
Alarms (include setpoints) ________
Overall uncertainty (°F, PSI) ________
Range of Display ________
Qualifications (seismic, environmental IEEE 323) ________

Calculator

Type (process computer, dedicated digital or analog calc.) ________
If process computer is used specify availability (% of time) ________
Single or redundant calculators ________
Selection Logic (highest T., lowest press.) ________
Qualifications (seismic, environmental, IEEE 323) ________
Calculational Technique (Steam Tables, Functional Fit, ranges) ________

Input

Temperature (RTD's or T/C's) ________
Temperature (number of sensors and locations) ________
Range of temperature sensors ________
Uncertainty* of temperature sensors (°F at 1) ________
Qualifications (seismic, environmental IEEE 323) ________

*Uncertainties must address conditions of forced flow and natural circulation

Backup Capability

Availability of Temp & Press ____________
Availability of Steam Tables, etc. ____________
Training of operators ____________
Procedures ____________

ADDITIONAL INSTRUMENTATION

POSITION

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement those devices cited in the preceding section giving an unambiguous, easy-to-interpret indication of inadequate core cooling. A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided.

CLARIFICATION

1. Design of new instrumentation should provide an unambiguous indication of inadequate core cooling. This may require new measurements to or a synthesis of existing measurements which meet safety-grade criteria.

2. The evaluation is to include reactor water level indication.

3. A commitment to provide the necessary analysis and to study advantages of various instruments to monitor water level core cooling is required in the response to the September 13, 1979 letter.

4. The indication of inadequate core cooling must be unambiguous, in that, it should have the following properties:

   a. it must indicate the existence of inadequate core cooling caused by various phenomena (i.e., high void fraction pumped flow as well as stagnant boil off).

   b. it must not erroneously indicate inadequate core cooling because of the presence of an unrelated phenomenon.

5. The indication must give advanced warning of the approach of inadequate core cooling.

6. The indication must cover the full range from normal operation to complete core uncovering. For example, if water level is chosen as the unambiguous indication, then the range of the instrument (or instruments) must cover the full range from normal water level to the bottom of the core.

DISCUSSION AND CONCLUSIONS

This item requires: the addition of a subcooling meter; procedures and training related to the use of existing instrumentation to detect inadequate core cooling and new instrumentation and procedures to provide an unambiguous indication of inadequate core cooling.

PSE&G has installed a subcooling meter and provided a description of the system in a letter, dated January 2, 1980. The system consists of sixty-five (65) temperature inputs from the core exit thermocouples plus two pressure inputs from a reactor coolant loop. The margin of subcooling is calculated by the plant process computer and is continuously displayed on a trend recorder near the computer output printers, at the rear of the control room. The following information can be easily called up from the plant process computer displayed on a CRT on the main console; highest thermocouple temperature, system pressure, saturation temperature, margin to saturation (in PSI and °F) and the location of the hottest thermocouple.

We find that the system of monitoring reactor coolant system subcooling meets all of the above requirements.

Procedures and training related to the use of existing instrumentation to detect inadequate core cooling are discussed in Section I.C.1.

In terms of new instrumentation to provide an unambiguous indication of inadequate core cooling, PSE&G has proposed to install a system of reactor vessel pressure drop measurement to be used in combination with the existing core exit thermocouples and the subcooling meter. PSE&G has proposed to measure differential pressure between the top of the reactor vessel and the bottom of the reactor vessel on two narrow range and two wide range instruments. The system is intended to function as follows: with the reactor coolant pumps off, the pressure drop between the top and the bottom of the vessel would indicate the collapsed liquid level (the equivalent liquid level without voids in the two-phase region) in the vessel. This would be read on the narrow range instrument in terms of feet of liquid. With the reactor coolant pumps running, the pressure drop from the top to the bottom of the vessel would provide an approximate indication of the void fraction in the vessel. This would be read on the wide range instrument as percent of full flow ΔP with the vessel filled with water.

The relationship between vessel differential pressure and core cooling involves complex phenomena, especially with one or more reactor coolant pumps operating. The adequacy of the system to indicate core cooling has not been demonstrated for conditions including: level swell, two-phased pumped flow; flow blockage; and system dynamics (including blowdown). PSE&G has met our requirement to provide a commitment to install instrumentation to detect inadequate core cooling and our requirement to provide a system design before fuel loading. The staff will continue to review the Salem Unit 2 design and will complete its review in sufficient time to allow for installation of an acceptable system by January 1981. The analyses and procedures related to the use of the new instrumentation must also be submitted and approved by NRC prior to January 1, 1981 which is the implementation date for the installation of the new instrumentation. We conclude that this requirement places no restrictions on Salem Unit 2 operation through full power.

II.G Emergency Power For Pressurizer Equipment (2.1.1 - NUREG-0578)

POSITION

Consistent with satisfying the requirements of General Design Criteria 10, 14, 15, 17 and 30 of Appendix A to 10 CFR Part 50 for the event of loss of offsite power, the following positions shall be implemented:

1. Motive and control components of the power-operated relief valves (PORVs) shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

2. Motive and control components associated with the PORV block valves shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

3. Motive and control power connections to the emergency buses for the PORVs and their associated block valves shall be through devices that have been qualified in accordance with safety-grade requirements.

4. The pressurizer level indication instrument channels shall be powered from the vital instrument buses. The buses shall have the capability of being supplied from either the offsite power source or the emergency power source when offsite power is not available.

CLARIFICATION

1. While the prevalent consideration from TMI Lessons Learned is being able to close the PORV/block valves, the design should retain, to the extent practicable, the capability to open these valves.

2. The motive and control power for the block valve should be supplied from an emergency power bus different from that which supplies the PORV.

3. Any changeover of the PORV and block valve motive and control power from the normal offsite power to the emergency onsite power is to be accomplished manually in the control room.

4. For those designs where instrument air is needed for operation, the electrical power supply requirement should be capable of being manually connected to the emergency power sources.

DISCUSSION AND CONCLUSION

We have reviewed the applicants' submittal of the emergency power supply design and discussed the design details with them.

We find the current Salem Unit 2 emergency power supply design for pressurizer level and relief and block valves to be in conformance with all requirements and clarifications of Lessons Learned Item 2.1.1 and is, therefore, acceptable.

II.K.1 IE Bulletins on Measures to Mitigate Small Break LOCAs and Loss of Feedwater Accidents

By letters dated April 14 and April 18, 1979, we transmitted IE Bulletin Nos. 79-06A and 79-06A (Revision 1) respectively, to Public Service Electric and Gas Company (PSE&G or the licensee). These Bulletins specified actions to be taken by the licensee to avoid occurrence of an event similar to that which occurred on March 28, 1979 at Three Mile Island, Unit 2 (TMI-2). By letters dated April 25, and June 1, 1979, PSE&G provided its response to these Bulletins for the Salem Nuclear Generating Station, Units 1 and 2. PSE&G supplemented these responses by letters dated July 13, and August 14, 1979, providing clarification and elaboration of certain of the Bulletin Action Items in response to our expressed concerns.

Our evaluation of the responses, as supplemented, is given below.

In Bulletin Action Item No. 1, licensees were requested to review the description of circumstances described in Enclosure 1 of IE Bulletin No. 79-05 (issued to all licensees with Babcock & Wilcox (B&W)-designed plants for action, and to all other licensees for information) and the preliminary chronology of the TMI-2 accident included in Enclosure 1 to IE Bulletin No. 79-05A (same distribution as IE Bulletin No. 79-05).

(a) This review should be directed toward understanding: (1) the extreme seriousness and consequences of the simultaneous blocking of both auxiliary feedwater trains at the Three Mile Island Unit 2 plant and other actions taken during the early phases of the accident; (2) the apparent operational errors which led to the eventual core damage; (3) that the potential exists, under certain accident or transient conditions, to have a water level in the pressurizer simultaneously with the reactor vessel not full of water; and (4) the necessity to systematically analyze plant conditions and parameters and take appropriate corrective action.

(b) Operational personnel should be instructed to: (1) not override automatic action of engineered safety features unless continued operation of engineered safety features will result in unsafe plant conditions (see Section 7a.); and (2) not make operational decisions based solely on a single plant parameter indication when one or more confirmatory indications are available.

(c). All licensed operators and plant management and supervisors with operational responsibilities were to participate in this review and such participation was to be documented in plant records.

On April 20, 1979, an NRC briefing team provided a detailed review of the circumstances described in Enclosure 1 of IE Bulletin No. 79-05 and the preliminary chronology of the TMI-2 accident (included in Enclosure 1 of of IE Bulletin No. 79-05A) to licensed station personnel and plant management. The briefing team consisted of an Office of Inspection and Enforcement (IE) Section Leader, an Operator Licensing Branch (NRR/OLB) representative, and the facility Principal/Resident Inspector. Attendance was documented, with any missing personnel being briefed at a later date by the NRC Principal/Resident Inspector. The NRC briefing also provided a detailed review of Action Item Nos. 1.a and 1.b of IE Bulletin No. 79-06A. In its response, PSE&G stated that an overall package of TMI-related training will include additional review of the sequence of events at TMI-2 and additional procedural requirements regarding the termination of engineered safety features. As part of PSE&G's existing operator qualification program, documentation is maintained of lecture attendance and procedure review.

We consider these actions to be acceptable responses to Action Item No. 1.

Action Item No. 2 of the Bulletin requested licensees to review actions required by operating procedures for coping with transients and accidents, with particular attention to (a) recognition of the possibility for forming voids large enough to compromise core cooling capability, (b) action required to prevent the formation of such voids, and (c) action required to enhance core cooling in the event such voids are formed. Emphasis in (a) was placed on natural circulation capability.

It its response to this Bulletin Action Item, PSE&G referenced the work of the Westinghouse Operating Plants Owners Group (PSE&G is a participating member of this Owners Group). In conjunction with Westinghouse, the Owners Group has developed generic guidelines for emergency operating procedures regarding small-break loss-of-coolant accidents (LOCAs). In its November 5, December 6, and December 27, 1979 letters to the Owners Group, the staff approved these guidelines for implementation by licensees with Westinghouse-designed reactors. The Owners Group and Westinghouse have also developed generic guidelines for emergency procedures regarding natural circulation. These generic guidelines were submitted as part of the Owners Group response to the requirements of NUREG-0578 regarding inadequate core cooling.

PSE&G committed to incorporate the generic guidelines developed by the Owners Group into its plant procedures and operator training program. In order to satisfy NUREG-0578 requirements (Item 2.1.9) this effort should be completed prior to operation above five percent power. Our evaluation of Item 2.1.9 is contained in Section I.C.1 of Part II to this supplement. Procedures based on these generic guidelines represent an acceptable method of complying with Bulletin Action Item No. 2.

PSE&G has also installed a computer program which provides the operator additional information relative to recognizing the possible formation of voids in the primary coolant system. This program computes the margin to saturation conditions based on the hottest in-core thermocouple reading and the reactor coolant system pressure. This program indicates the degrees of subcooling. An alarm is generated if 50 °F of subcooling does not exist whenever reactor power is less than 0.25 percent. An alarm is also generated if the difference between actual and saturation pressure is less than 200 psi.

Based on our review, we find that PSE&G has provided an acceptable response to Bulletin Action Item No. 2.

Bulletin Action Item No. 3 requested that licensees with facilities that used prassurizer water level coincident with pressurizer pressure for automatic initiation of safety injection into the reactor coolant system, trip the low pressurizer level setpoint bistables such that, when the pressurizer pressure reached the low setpoint, safety injection would be initiated regardless of the pressurizer level. The pressurizer level bistables could be returned to their normal operating positions during the pressurizer pressure channel functional surveillance tests.

In response to this item, PSE&G modified the safety injection initiation logic for Salem Unit 2. This design change moves the level input requirement and changes the pressure coincidence to a two-out-of-three logic for initiation of safety injection.

Existing procedures direct the operators to manually initiate any protection functions, if the automatic initiation fails. Although this ensures manual initiation of safety injection on low pressurizer pressure, additional training was given to operating personnel in light of the TMI-2 accident which addressed the revised logic. This training effort was completed in August 1979.

Based on our review of this information, we find PSE&G's response to Bulletin Action Item No. 3 acceptable.

Bulletin Action Item No. 4 requested that licensees review the containment isolation initiation design and procedures, and implement all changes necessary to permit containment isolation, whether manual or automatic, of all lines whose isolation would not degrade needed safety features or cooling capability, upon automatic initiation of safety injection.

The Salem Unit 2 design provides for automatic initiation of containment isolation upon safety injection actuation, as called for in the bulletin. This aspect of PSE&G's response is therefore acceptable.

Containment isolation consists of a Phase A and a Phase B isolation. Phase A involves closure of automatic valves in all nonessential process lines; Phase B isolates all remaining process lines, except for safety injection, containment spray, and auxiliary feedwater.

The reactor coolant pump seal water discharge line is isolated upon a Phase A signal. The seal water supply line is not provided with isolation valves. The component cooling water supply and return lines for the reactor coolant pumps are isolated by a Phase B signal. The reactor coolant pumps do not trip automatically on either isolation signal. Therefore, the pumps must be manually tripped following a Phase B isolation, since component cooling to the motor coolers and thermal barriers is lost.

We find that PSE&G has adequately addressed the concerns expressed in Bulletin Action Item No. 4.

In Bulletin Action Item No. 5, licensees with facilities at which the auxiliary feedwater system is not automatically initiated were requested to prepare and implement immediately procedures which required the stationing of an individual (with no other assigned concurrent duties and in direct and continuous communication with the control room) to promptly initiate adequate auxiliary feedwater to the steam generator(s) for those transients or accidents the consequences of which could be limited by such action.

The auxiliary feedwater system is automatically initiated at Salem Unit 2, with no operator action required in order to ensure adequate flow. Therefore, Bulletin Action Item No. 5 does not apply to this plant.

Bulletin Action Item No. 6 requested that licensees prepare and implement immediately procedures which:

(a) Identified those plant indications (such as valve discharge piping temperature, valve position indication, or valve discharge relief tank temperature or pressure indication) which plant operators could utilize to determine that the pressurizer power operated relief valve(s) are open, and

(b) Directed the plant operators to manually close the power-operated relief block valve(s) when reactor coolant system pressure was reduced to below the setpoint for normal automatic closure of the power-operated relief valve(s) and the valve(s) remain in the stuck open position.

Current Salem Unit 2 procedures assure that operating personnel are aware of plant indications available to detect an open pressurizer PORV. These procedures include instructions to isolate the PORV if it is stuck open. In its response to this item, PSE&G also identified the information that is available to the operator which provides indication of an open PORV. Salem Unit 1 uses the PORVs for low temperature overpressure protection. Salem Unit 2 has additional valves for low-temperature overpressure protection located downstream of the motor-operated block valve. These are connected in parallel with the PORVs. PSE&G has revised the Emergency Instruction for failure of a PORV or safety valve on the pressurizer to include these valves (PR 47 and 48) as possible sources of leakage. Due to the system arrangement, the existing steps in the procedure are sufficient to isolate a leaking valve.

Based on our review, we find PSE&G's response to Bulletin Action Item No. 6 acceptable.

In Bulletin Action Item No. 7, licensees were requested to review the action directed by the operating procedures and training instructions to ensure that:

(a) Operators do not override automatic actions of engineered safety features, unless continued operation of engineered safety features would result in unsafe plant conditions. For example, if continued operation of engineered safety features would threaten reactor vessel integrity, the high pressure injection (HPI) should be secured (as noted in b(2) below).

(b) Operating procedures currently, or are revised to, specify that, if the HPI system had been automatically actuated because of a low pressure condition, it must remain in operation until either:

(1) Both low pressure injection (LPI) pumps are in operation and flowing for 20 minutes or longer; at a rate which would assure stable plant behavior; or

(2) The HPI system has been in operation for 20 minutes, and all hot and cold leg temperatures are at least 50 degrees Fahrenheit below the saturation temperature for the existing RCS pressure. If 50 degrees subcooling cannot be maintained after HPI cutoff, the HPI shall be reactivated. The degree of subcooling beyond 50 degrees and the length of time HPI has been in operation shall be limited by the pressure/temperature considerations for the vessel integrity.

(c) Operating procedures currently, or are revised to, specify that, in the event of HPI initiation with reactor coolant pumps (RCP) operating, at least one RCP shall remain operating for two-loop plants and at least two RCPs shall remain operating for 3 or 4 loop plants, as long as the pump(s) is providing forced flow.

(d) Operators are provided additional information and instructions to not rely upon pressurizer level indication alone, but to also examine pressurizer pressure and other plant parameter indications in evaluating plant conditions, e.g., water inventory in the reactor primary system.

In its July 13, 1979 supplemental response to Bulletin Action Item No. 7.a, PSE&G stated that a complete review of the Salem station procedures indicated that the only engineered safety feature which is overridden is safety injection. PSE&G referenced the work of the Westinghouse Operating Plants Owners Group concerning resolution with the NRC staff of the conditions under which safety injection may be overridden and terminated. The PSE&G response included a commitment to incorporate the resolution of this issue between the Owners Group and the staff into the station procedures for both Units 1 and 2. This issue has now been resolved (see our evaluation of Item 7.b below).

PSE&G also stated that it had discovered that it was possible to inadvertently override the RMS interlock on the Containment Ventilation System by improper operation of the reset functions. To prevent occurrence of this situation, additional instructions were issued to the operators and were included in the procedures and the operator training program. Because of the discovery of this problem, PSE&G

undertook an investigation to verify that there were no similar situations. The results of that review verified that safety functions are not overridden and are allowed to go to completion, as considered in the plant design bases.

We find that PSE&G has addressed the concerns expressed in Bulletin Action Item 7.a in an acceptable manner.

In response to Bulletin Action Item No. 7.b, as in the preceding item, PSE&G committed to the resolution of the issue regarding termination of safety injection between the Owners Group and the staff. In our November 5, December 6, and December 27, 1979 letters to the Owners Group, we approved the Westinghouse generic guidelines for emergency procedures regarding small break LOCAs for incorporation by licensees into their plant procedures. These approved guidelines include the following criteria (taken from the enclosure to our December 27, 1979 letter) for termination of safety injection:

(1) The reactor coolant system pressure is greater than 2000 pounds per square inch gauge and increasing, <u>and</u>

(2) The pressurizer water level is greater than the programmed no-load water level, <u>and</u>

(3) The reactor coolant indicated subcooling is greater than (insert plant-specific value, which is the sum of the errors for the temperature measurement system used and the pressure measurement system translated into temperature using the saturation tables), <u>and</u>

(4) The water level in at least one steam generator is stable and increasing, as verified by auxiliary feedwater flow to that unit. Auxiliary feedwater flow to the unaffected steam generator should be greater than (<u>a value in gallons per minute sufficient to remove decay heat after 20 minutes following reactor trip</u>) until the indicated level is returned to within the narrow range level instrument.

Details of our evaluation of this issue are included in the report (NUREG-0611) of our generic review of Westinghouse-designed operating plants.

The Office of Inspection and Enforcement has verified that the approved Westinghouse generic safety injection termination criteria have been properly incorporated in the Salem plant procedures. Based on our review, we find that PSE&G's actions with regard to Bulletin Action Item No. 7.b are acceptable.

Another issue on which the Westinghouse Owners Group worked, in conjunction with Westinghouse, to achieve resolution with the staff was the matter of reactor coolant pump operation following a small break LOCA (Bulletin Action Item No. 7.c). On July 26, 1979, IE Bulletin No. 79-06C superseded Action Item No. 7.c of IE Bulletin No. 79-06A. IE Bulletin No. 79-06C required that, as a short-term action, licensees were to trip all reactor coolant pumps after an initiation of safety injection caused by low reactor coolant system pressure. In its August 29, 1979 response to IE Bulletin No. 79-06C, PSE&G stated its conformance with this requirement. This action was to remain in effect until the results of analyses specified in IE Bulletin No. 79-06C had been used to develop new guidelines for operator action.

We have completed our review of the reactor coolant pump trip issue with the Owners Group. The generic guidelines for emergency procedures regarding small break LOCAs, which we approved in our November 5 and December 6, 1979 letters to the Owners Group, contain the approved pump trip criteria for Westinghouse-designed operating plants. Basically, they are as follows:

(1) Stop all reactor coolant pumps after high pressure safety injection pump operation has been verified, and when the wide range reactor pressure is at (plant-specific pressure derived from secondary system relief capacity, primary-to-secondary system pressure difference, and instrument inaccuracies).

Appropriate cautions have been included in the guidelines regarding isolation of component cooling water to the reactor coolant pumps and maintaining seal injection flow to preclude pump damage due to inadequate cooling. The details of our review of the pump trip issue are reported in NUREG-0623.

The Office of Inspection and Enforcement has confirmed that PSE&G has incorporated the pump trip criteria as specified in the approved Westinghouse generic guidelines into the Salem plant procedures. Therefore, we find PSE&G's response to Bulletin Action Item No. 7.c acceptable.

Bulletin Action Item No. 8 required that licensees review alignment requirements and controls for all safety-related valves necessary for proper operation of engineered safety features. PSE&G completed the required review and incorporated all necessary changes into the procedures for Salem Units 1 and 2. The status of key safety system valves at Salem Unit 1 was verified by visual examination shortly after the TMI-2 accident.

Based on our review, we find PSE&G's response to Bulletin Action Item No. 8 acceptable.

In Bulletin Action Item No. 9, licensees were requested to review their procedures to assure that radioactivity will not be inadvertently released from containment. Particular emphasis was placed on resetting of engineered safety features (ESFs) and the effect of this action on valves controlling the release of radioactivity.

In its response, PSE&G identified all systems which are designed to transfer potentially radioactive fluids from containment. For each of these systems, PSE&G addressed high radiation interlocks, containment isolation (Phase A and Phase B), and operability assurances, as requested. Two instances were identified, the Reactor Coolant Drain Tank pump discharge line and the Pressurizer Relief Tank gas analyzer line, which could result in the inadvertent transfer of radioactive material from the containment. PSE&G stated that design changes to revise the control circuitry to prevent the occurrence of an open pathway in these two instances would be implemented before Salem Unit 1 startup for Cycle 2. This change was also implemented on Salem Unit 2.

Based on our review of PSE&G's response, we find that PSE&G has adequately addressed the concerns expressed in Bulletin Action Item No. 9.

In addition to the above, the staff's implementation of Item 2.1.4 of NUREG-0578 provides further assurance that the inadvertent release of radioactivity from containment upon resetting of ESFs will be precluded. Our review of NUREG-0578 Item 2.1.4 implementation will be reported in a supplement to the Safety Evaluation Report.

Bulletin Action Item No. 10 required that licensees review and modify, as necessary, maintenance and test procedures for safety-related systems to ensure that they require that: (a) redundant systems are operable before a system is taken out of service, (b) systems are operable when returned to service, and (c) operators are made aware of the status of these systems.

PSE&G has reviewed station procedures and revised them, where necessary, to detail requirements for verifying the operability of redundant equipment prior to removing safety-related equipment from service and verifying the operability of equipment when it is returned to service. Both systems level considerations and individual safety-system equipment are addressed.

PSE&G stated that the Shift Supervisor/Senior Shift Supervisor is responsible for approving all requests for removal of equipment for service. The control operator prepares the necessary administrative tags which are used to identify equipment removed from service. The equipment operator places these tags on the equipment taken out of service. The control operator also indicates control room equipment out-of-service by the use of tags and other identification methods.

Based on our review, we find that PSE&G has adequately addressed all of the concerns expressed in Bulletin Action Item No. 10.

Bulletin Action Item No. 11 requested licensees to review their prompt reporting procedures for NRC notification to assure that the NRC is notified within one hour of the time the reactor is not in a controlled or expected condition of operation. Further, at that time, an open, continuous communication channel shall be established and maintained with the NRC.

In response to this item, PSE&G revised and issued Station Supervisory Letter SL-9, "Notification of Federal and State Agencies," to require notification of the NRC within one hour of the plant being in an uncontrolled or unexpected condition. Telephone lines to establish the required open line of communication between the Salem plant and IE Region I via Bethesda, Maryland have been installed and are now functional. Additional telephone lines to provide communications from the Salem plant to the NRC for radiation protection/chemistry matters have also been installed. The Station Emergency Plan has been revised to include the location and use of these lines. Based on our review, we find PSE&G's actions to be an acceptable response to Bulletin Action Item No. 11.

In Bulletin Action Item No. 12, licensees were requested to review operating modes and procedures to deal with significant amounts of hydrogen gas that may be generated during a transient or other accident, that would either remain inside the primary system or be released to the containment.

In its response to this item, PSE&G stated that it had reviewed the modes for controlling hydrogen in the reactor coolant system. The options considered by PSE&G for removal of hydrogen from the reactor coolant system included (1) stripping hydrogen from the reactor coolant to the pressurizer vapor space and venting to the pressurizer relief tank, (2) removing hydrogen from the reactor coolant system via the letdown line and stripping it in the volume control tank and venting through the waste gas system, and (3) in the event of a LOCA, hydrogen would vent with steam into containment.

PSE&G also described modes and procedures for removal of a noncondensible gas bubble from the primary coolant system while maintaining core cooling.

In addition, PSE&G participated in the Westinghouse Operating Plant Owners Group efforts to develop generic guidelines for emergency operational procedures regarding inadequate core cooling in response to the requirements of Item 2.1.9 of NUREG-0578. Treatment of noncondensible gas in the reactor coolant system is being considered in the development of these guidelines. Our evaluation of Item 2.1.9 is contained in Section I.C.1 of Part II to this supplement.

During subsequent discussions with PSE&G, we were informed that each of the options for dealing with hydrogen described above would be incorporated in the Salem Unit 1 plant procedures, where needed, to address various plant conditions. This implementation was to have been completed by January 1, 1980. Our Office of Inspection and Enforcement will verify that this commitment has also been fulfilled for Salem Unit 2.

Based on our review, we find that PSE&G's actions in response to the concerns expressed in Bulletin Action Item No. 12 are acceptable.

Bulletin Action Item No. 13 requested licensees to propose changes to the plant Technical Specifications, as required, which had to be modified as a result of implementing Action Items 1 through 12.

In its June 1, 1979 letter, PSE&G identified the design changes and changes to the Salem Unit 1 Technical Specifications that were required, up to that time, to implement Bulletin Action Items 1 through 12. According to PSE&G, the only required Technical Specification change reflected deletion of the coincident Pressurizer Low Level and Low Pressure Signals for initiating safety injection. As discussed in our evaluation of Bulletin Action Item No. 3, the revised design consists of a two-out-of-three coincidence of Presurizer Low Pressure Signals. The Salem Unit 2 Technical Specifications will reflect this design change.

Based on our review, we find that PSE&G has made an adequate response to Bulletin Action Item No. 13.

IE Bulletin No. 79-06C was issued on July 26, 1979 to all licensees with Westinghouse-designed operating plants. This bulletin, which is applicable to all operating PWRs, revised one of the positions in IE Bulletin No. 79-06A and introduced supplemental requirements. The most salient feature of this bulletin is that it reversed the requirement in the previous TMI-2 related bulletins regarding the operation of the reactor coolant pumps during a small-break LOCA. This bulletin requires that the reactor coolant pumps be tripped upon a small-break LOCA, whereas the previous bulletins required that some of the reactor coolant pumps be kept running.

IE Bulletin No. 79-06C contained five short-term actions and one long-term action to be implemented by licensees. In its August 29, 1979 letter, F. W. Schneider to Boyce H. Grier, PSE&G, provided responses to IE Bulletin No. 79-06C for Salem Unit 1. By letter dated March 28, 1980, PSE&G provided its response to IE Bulletin No. 79-06C for Salem Unit 2. In this response, PSE&G informed us that the August 29, 1979 response also applies to Salem Unit 2. Our evaluation of PSE&G's responses is summarized below.

Short-Term Actions:

Item No. 1 required (a) that all operating reactor coolant pumps be tripped upon reactor trip and initiation of high pressure injection caused by low reactor coolant system pressure, and (b) that two licensed operators be in the control room at all times (three in the case of dual control rooms) to accomplish the above action and any required supplemental actions.

In response to Item No. 1.a, PSE&G revised the Station Emergency Procedures to implement the required actions. We find PSE&G's response to Item No. 1.a acceptable.

In response to Item No. 1.b PSE&G issued a station operating memo conforming to the bulletin requirement.

Item Nos. 2 and 3 required that licensees perform analyses of a range of small break LOCAs and a range of time lapses between reactor trip and pump trip (Item No. 2), and that guidelines for operator action for both LOCA and non-LOCA transients be developed (Item No. 3) based on the reactor coolant pump trip requirements originating from the analyses required by Item No. 2.

In its response to these items, PSE&G referenced the work of the Westinghouse Owners Group (PSE&G is a participating member). The Owners Group submitted the Westinghouse report WCAP-9584, "Analysis of Delayed Reactor Coolant Pump Trip During Small Loss-of-Coolant Accident for Westinghouse Nuclear Steam Supply Systems," as a generic response to Item Nos. 2 and 3. Since the generic guidelines for emergency operating procedures originally submitted in the small break LOCA analysis report, WCAP-9600, "Report on Small Break Accidents for Westinghouse NSSS System", were considered consistent with the pump trip guidance, additional guidelines were not proposed. By letters dated November 5, December 6, and December 27, 1979, D. F. Ross, Jr., to Cordell Reed, we approved the generic guidelines for emergency operating procedures regarding small break LOCAs for all operating Westinghouse-designed plants. Our evaluation of the Westinghouse analyses pertaining to reactor coolant pump trip is contained in NUREG-0623. The effort of the Westinghouse Owners Group represents an acceptable method of meeting the requirements of Item Nos. 2 and 3.

Item No. 4 required that emergency procedures, based on the guidelines developed under Item No. 3 above, be developed by licensees and that all licensed reactor operators and senior reactor operators be retrained as required. The small break LOCA procedures (Item 2.1.9.a of NUREG-0578) are required to be implemented prior to operation above five percent power. Our evaluation of PSE&G's implementation of Item 2.1.9.a of NUREG-0578 is contained in Section I.C.1 of Part II to this supplement.

Item No. 5 was related to inadequate core cooling (as specified in Item 2.1.9.b of NUREG-0578). This item required that licensees perform analyses of inadequate core cooling, develop guidelines for emergency procedures based on these analyses, and implement procedures based on the above-mentioned guidelines. In response to this item, PSE&G referenced the work of the Westinghouse Owners Group. By letter dated October 30, 1979, the Owners Group submitted a document, "Westinghouse Inadequate Core Cooling Analysis Performed to Meet the Requirements Set Forth in NUREG-0578", which addressed this item. Our evaluation of Item 2.1.9.b of NUREG-0578 (inadequate core cooling) is contained in Section I.C.1 of Part II to this supplement.

Long-Term Action:

Item No. 1 pertained to the design of circuitry which would provide for automatic tripping of the operating reactor coolant pumps under all circumstances in which such action was considered necessary. In its response to this item, PSE&G stated that it did not believe that the automatic tripping of the reactor coolant pumps should be a required function. Our evaluation of this item is contained in NUREG-0623 along with corresponding recommendations. Implementation of the NUREG-0623 recommendations as licensing requirements will be carried out by the staff with an appropriate implementation schedule upon approval by the Director of the Office of Nuclear Reactor Regulation within the scope of Item II.K.3 of the NRC's TMI-2 Action Plan (NUREG-0660).

II.K.3 <u>Generic Review Matters - Small Break LOCAs and Loss of Feedwater Accidents</u>

As part of its generic review of small break LOCAs and feedwater transients in Westinghouse-designed operating plants, the NRC's Bulletins and Orders Task Force (B&OTF) performed a review of the Salem Unit 1 auxiliary feedwater system. The B&OTF generic review is described in NUREG-0611, "Generic Evaluation of Feedwater Transients and Small Break Loss of Coolant Accidents in Westinghouse-Designed Operating Plants".

By letter dated September 21, 1979, the NRC staff transmitted the licensing requirements for the Salem Unit 1 auxiliary feedwater system resulting from the above-mentioned review to PSE&G. PSE&G provided its response to these requirements in its November 1, 1979 letter. Our review of PSE&G's response is currently in progress.

Since the Salem Unit 2 auxiliary feedwater system is essentially identical to that at Salem Unit 1, this evaluation is also applicable to Salem Unit 2. Completion of the auxiliary feedwater system reliability analysis and appropriate system modifications is classified as a requirement for full power operation for near term operating license applications in Appendix A of the NRC TMI-2 Action Plan (NUREG-0660) and is not necessary for low power testing. Hence, we will report the results of the implementation of the B&OTF auxiliary feedwater system requirements in another supplement to this Safety Evaluation Report prior to full power operation of Salem Unit 2.

Our review of small break LOCAs for Salem Unit 2 is discussed in Section I.C.1 of Part II to this report.

The remainder of the recommendations identified in NUREG-0611 will be implemented with an appropriate implementation schedule in the NRC TMI-2 Action Plan.

III EMERGENCY PREPARATIONS AND RADIATION PROTECTION

III.A.1.2 Improve Licensee Facilities for Responding to Emergencies

III.A.1.2(a) Technical Support Center (2.2.2.b - NUREG-0578)

POSITION

Each operating nuclear power plant shall maintain an onsite technical support center (TSC) separate from and in close proximity to the control room that has the capability to display and transmit plant status to those individuals who are knowledgeable of and responsible for engineering and management support of reactor operations in the event of an accident. The center shall be habitable to the same degree as the control room for postulated accident conditions. The licensee shall revise his emergency plans as necessary to incorporate the role and location of the technical support center. Records that pertain to the as-built conditions and layout of structures, systems and components shall be readily available to personnel in the TSC.

CLARIFICATION

1. By January 1, 1980, the licensee shall meet the items that follow.

   a. Establish a TSC and provide a complete description.

   b. Provide plans and procedures for engineering/management support and staffing of the TSC.

   c. Install dedicated communications between the TSC and the control room, near site emergency operations center, and the NRC.

   d. Provide monitoring (either portable or permanent) for both direct radiation and airborne radioactive contaminants. The monitors should provide warning if the radiation levels in the support center are reaching potentially dangerous levels. The licensee should designate action levels to define when protective measures should be taken (such as using breathing apparatus and potassium iodide tablets, or evacuation to the control room).

e. Assimilate or ensure access to Technical Data, including the licensee's best effort to have direct display of plant parameters, necessary for assessment in the TSC.

f. Develop procedures for performing this accident assessment function from the control room should the TSC become uninhabitable, and

g. Submit to the NRC a longer range plan for upgrading the TSC to meet all requirements.

Each licensee is encouraged to provide additional upgrading of the TSC as soon as practical, but no later than January 1, 1981.

It is recommended that the TSC be located onsite in close proximity to the control room.

The TSC should be large enough to house 25 persons.

The center should be activated in accordance with the "Alert" level as defined in the NRC document "Draft Emergency Action Level Guidelines, NUREG-0610", dated September, 1979.

The instrumentation to be located in the TSC should be qualitatively comparable to that in the control room.

The power supply to the TSC instrumentation should be reliable and of a quality compatible with the TSC instrumentation requirements.

Each licensee should establish the technical data requirements for the TSC. As a minimum, data should be available to permit the assessment of:

Plant Safety Systems Parameters
In-Plant Radiological Parameters
Offsite Radiological Parameters

Each licensee should review current technology as regards transmission of those parameters identified for TSC display.

The center should be well built in accordance with sound engineering practice. However, in the event that access to the center is prevented, each licensee should prepare a backup plan for responding to an emergency from the control room.

The licensee should provide protection for the technical support center personnel from radiological hazards.

DISCUSSION AND CONCLUSIONS

A temporary onsite Technical Support Center (OTSC) has been established on the third floor of the Clean Facilities Building, which is adjacent to Salem Unit 1 and accessible by personnel from both units. The Clean Facilities Building is within the plant security boundary. The room used for the OTSC is approximately 2500 square feet and will easily accommodate 25 people. The station Technical Document Room is also housed within the building. Technical information such as general arrangement drawings, piping isometrics, electrical drawings, system specifications, and plant procedures that might be needed during an emergency are easily accessible.

The OTSC provides an assembly area for technical personnel. Communications equipment has been installed which provides direct lines to the control room, Operations Support Center, and Senior Shift Supervisor's office as well as various outside agencies including PSE&G's Newark Headquarters, NRC and appropriate police and civil defense agencies.

The station Emergency Plan Manual has been revised to incorporate activation of the OTSC. This manual identifies the personnel who will report to and make up the OTSC staff if the Emergency Plan is implemented. If the OTSC becomes uninhabitable for any reason, the Emergency Director may choose to utilize the Senior Shift Supervisor's office in the Control Room area since adequate communications are located in that area as well as the OTSC.

Display of plant parameter information in the OTSC consists of data links to the plant computer and the Radiation Monitoring System computer. Data presentation will consist of a slave CRT which will display in the OTSC any information requested by the operators in the plant control room. In addition to this CRT display, a typewriter terminal is available in the OTSC which has the capability to access any of the plant data stored in the computer. A pre-selected number of key parameters can be 'trended' upon request.

The OTSC is provided with radiation monitors capable of detecting both direct and airborne radioactive containments. Visual and audible alarms are provided. Action levels to define requirements for protective measures (such as using breathing apparatus and potassium iodide tablets or evacuation to the control room) are delineated in the Station Emergency Plan Implementation Manual.

PSE&G has provided a description of its plans to upgrade the OTSC to meet all long term requirements. Demarcation of functional areas, modifications to the ventilation system, installation of radiation shielding, changes to the power supplies and additional information display are among the more significant modifications that will be made. PSE&G is on schedule with the upgrading effort.

PSE&G has met this requirement since (1) an OTSC has been established with adequate communications links and access to plant parameter data and technical information, and (2) appropriate procedural revisions have been made to establish and man the OTSC at the outset of an emergency. Plans for the permanent OTSC provide reasonable assurance that long term requirements will also be met.

III.A.1.2(b) <u>Onsite Operational Support Center</u> (2.2.2.c - NUREG-0578)

<u>POSITION</u>

An area to be designated as the onsite operational support center shall be established. It shall be separate from the control room and shall be the place to which the operations support personnel will report in the emergency situation. Communications with the control room shall be provided. The emergency plan shall be revised to reflect the existence of the center and to establish the methods and lines of communication and management.

<u>DISCUSSION AND CONCLUSIONS</u>

PSE&G has established an Onsite Operational Support Center (OOSC) in the hallway between the Salem Unit 1 and Unit 2 control rooms, the Senior Shift Supervisor's office and the file room. From this area communication by telephone, station page and station security radios are available to the control room, other station extensions and offsite. In the event of an emergency, the operating personnel not on duty in the control rooms and support personnel will report to the OOSC for accountability. Others reporting to the OOSC include operators scheduled to relieve the on duty shift, fire brigade members and first aid team members. The first Senior Shift Supervisor or Shift Supervisor reporting to the OOSC will assume the duties of OOSC Supervisor and will act in that capacity until relieved by an individual appointed by the Emergency Director.

PSE&G has met this requirement.

III.A.3 Improving NRC Emergency Preparedness

III.A.3.3 Communications

POSITION

Direct dedicated telephone lines (OPX) have been installed at each operating power plant and selected fuel facilities; these lines are for immediate notification and continuous communication with NRC concerning facility status. A second direct and dedicated network for health physics and environmental information is to be installed by February 1980.

DISCUSSION AND CONCLUSIONS

NRC OPX telephones have been installed at the Salem site. These telephones provide direct "hot line" communications with NRC headquarters and are located in each control room, the shift supervisor's office, the Technical Support Center and the NRC resident office. A second network (NRC SS-4) for health physics and environmental information has also been installed at the Salem site. The network includes dial telephones in the health physics office, the NRC resident office, the Technical Support Center, and the near site Emergency Operations Center. This task is complete.

III.B Emergency Preparedness of State and Local Governments

III.B.1 Near-Term Actions

We conclude that the following approach should be used to evaluate emergency preparedness for current applications for fuel loading and low power operation.

1. The combined applicant, State and local emergency plans must meet:

   a. Current regulatory requirements of 10 CFR Part 50, Appendix E.

   b. Regulatory position statements in Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants", Revision 1, March 1977.

   c. Essential planning elements in NUREG 75/111, "Guide and Check-list for Development and Evaluation of State and Local Government Radiological Emergency Response Plans in Support of Fixed Nuclear Facilities," including Supplement No. 1 thereto dated March 15, 1977.

2. Identification of the criteria specified in NUREG-0654 which are not covered in the applicants' plan and will need to be satisfactorily addressed prior to the issuance of a full power license.

The staff's review of the applicants' emergency plans and our findings are documented in Section 13.2 of the Safety Evaluation Report, Section 13.2 of Supplement No. 3, and Section 13.2 of Part I to Supplement No. 4. We have determined that the plans meet the requirements of Appendix E to 10 CFR Part 50, and conform to the regulatory position statements in Revision 1 to Regulatory Guide 1.101.

The radiological emergency response plans for the States of New Jersey and Delaware were reviewed by the appropriate Federal Interagency Regional Advisory Committee for Radiological Emergency Response Planning. The documents reviewed were the "New Jersey State PIPAG Manual," dated August 1976 (with Amendment dated November 1, 1977) and Annex 5, "Radiological Emergency Response Plan," to the Delaware Emergency Operations Plan as amended through June 1978. The review was conducted against the "Guide and Checklist for Development and Evaluation of State and Local Government Radiological Emergency Response Plans in Support of Fixed Nuclear Facilities," (NUREG 75/111) including Supplement No. 1 to that publication dated March 15, 1977, which identifies those items essential for NRC concurrence in State plans. As a result of these reviews, and in accordance with the provisions of the Federal Register Notice (Volume 40, No. 248, December 24, 1975) the NRC concurred formally in the New Jersey plan on September 30, 1977, and in the Delaware plan on July 24, 1978. The Defense Civil Preparedness Agency, the Federal Preparedness Administration, and the Federal Disaster Assistance Administration, all of which are now part of the Federal Emergency Management Agency (FEMA), actively participated in the review of these plans and joined in the recommendation for concurrence.

As a result of the Commission's action plan for promptly upgrading emergency preparedness at nuclear power reactors (SECY 79-540), the Emergency Planning Review Team conducted a site visit and technical meeting with the applicants, and the New Jersey and Delaware State and local officials, in October, 1979. In response to our visit, the applicants submitted a proposed revision to the Salem Emergency Plan on November 19, 1979 and a second revision on January 25, 1980. As a result of our review against the interim criteria set forth in NUREG-0654, dated January, 1980, and in accordance with the NRC staff requirement in item 2 above, we have identified additional planning elements which will be required prior to the issuance of a full power license. These elements have been identified in our letter to the applicants dated March 28, 1980. Some of the more salient areas include the following:

(a) Expanded planning to include the full accident spectrum as outlined in NUREG-0396.

(b) Provisions for early warning and clear instructions to the public in the event of a serious accident.

(c) Establishment of a near-site emergency operations facility.

(d) Adoption of the emergency classification scheme, together with emergency action levels, as set forth in NUREG-0610.

(e) Implementation of a public information program.

(f) Improved State and local emergency plans which conform to the upgraded joint NRC/FEMA criteria contained in NUREG-0654.

Based on the above, we find that the combined applicant, State and local emergency plans meet the requirements set forth in Item 1 above for fuel loading and low power operation, and that they provide reasonable assurance that appropriate protective measures can and will be taken in the event of an emergency to protect public health and safety.

FEMA/NRC INTERIM AGREEMENT ON CRITERIA FOR LOW POWER TESTING AT NEW COMMERCIAL NUCLEAR FACILITIES

The FEMA/NRC Steering Committee has agreed that for the purposes of low power testing (up to 5% power) at new commercial nuclear facilities that the public health and safety is adequately protected if such facility is located in a State which had received a concurrence under the previous voluntary concurrence program, administered by the NRC and based on evaluation by a multi-agency Federal Regional Advisory Committee. In addition, operator plans at individual sites must be consistent with both the existing NRC Appendix E to 10 CFR Part 50 and NRC Regulatory Guide 1.101 in order to assure adequate protection of the public health and safety prior to low power testing.

NRC and FEMA agree that State, local and nuclear facility operator plans must be adequate when judged against the criteria contained in NUREG-0654 and FEMA/REP-1 prior to full scale commercial operation.

This agreement is based on the considerations discussed in the exchange of letters between H. Denton, NRC and J. McConnell, FEMA, both dated February 14, 1980.

The parties note that the North Anna, Salem and Diablo Canyon sites are located in Virginia, New Jersey and California respectively, all of which have received prior NRC concurrence in State Plans. The Salem facility is located near the Delaware border; the radiological emergency plan of the State of Delaware has also received prior NRC concurrence. NRC stipulates that individual nuclear facility operator plans at these plants are in compliance with Appendix E and are consistent with Regulatory Guide 1.101.

III.D.3 Worker Radiation Protection Improvements

III.D.3.3 In-Plant Radiation Monitoring (Partial) (2.1.8.c - NUREG-0578)

POSITION

Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident.

CLARIFICATION

Use of Portable versus Stationary Monitoring Equipment

Effective monitoring of increasing iodine levels in the buildings under accident conditions must include the use of portable instruments for the following reasons:

a. The physical size of the auxiliary/fuel handling building precludes locating stationary monitoring instrumentation at all areas where airborne iodine concentration data might be required.

b. Unanticipated isolated "hot spots" may occur in locations where no stationary monitoring instrumentation is located.

c. Unexpectedly high background radiation levels near stationary monitoring instrumentation after an accident may interfere with filter radiation readings.

d. The time required to retrieve samples after an accident may result in high personnel exposures if these filters are located in high dose rate areas.

Iodine Filters and Measurement Techniques

A. The following are short-term recommendations and shall be implemented by the licensee by January 1, 1980. The licensee shall have the capability to accurately detect the presence of iodine in the region of interest following an accident. This can be accomplished by using a portable or cart-mounted iodine sampler with attached single channel analyzer (SCA). The SCA window should be calibrated to the 365 keV of I-131. A representative air sample shall be taken and then counted for I-131 using the SCA. This will give an initial conservative estimate of presence of iodine and can be used to determine if respiratory protection is required. Care must be taken to assure that the counting system is not saturated as a result of too much activity collected on the sampling cartridge.

B. By January 1, 1981, the licensee shall have the capability to remove the sampling cartridge to a low background, low contamination area for further analysis. This area should be ventilated with clean air containing no airborne radionuclides which may contribute to inaccuracies in analyzing the sample. Here, the sample should first be purged of any entrapped noble gases using nitrogen gas or clean air free of noble bases. The licensee shall have the capability to measure accurately the iodine concentrations present on these samples and effluent charcoal samples under accident conditions.

DISCUSSION AND CONCLUSIONS

The applicants state that Salem Unit 2 has portable low volume air samplers equipped with single channel analyzer capability for measuring I-131. Collected samples are analyzed by gamma radiation spectrum analysis using portable gamma scintillation counting systems. In addition, collected samples may be further analyzed in the plant counting facilities using Ge(Li) detectors.

10 CFR Part 20 provides criteria for control of exposures of individuals to radiation in restricted areas, including airborne iodine. Since iodine concentrates in the thyroid gland, airborne concentrations must be known in order to evaluate the potential dose to the thyroid. If the airborne iodine concentration is overestimated, plant personnel may be required to perform operational functions while wearing respiratory protective equipment which may result in diminished personnel performance during an accident. The purpose of this recommendation is to improve the validity of measurement of airborne iodine concentrations within nuclear power plants.

The equipment and procedures described by the applicants meet our position in NUREG-0578 and are, therefore, acceptable.

IV RECOMMENDATIONS OF NRC SPECIAL INQUIRY GROUP

Item 1 Control Room Design Review

As part of the staff actions following the TMI-2 accident, we will require that all licensees and applicants for operating licenses conduct a detailed control room design review. We expect these reviews to be initiated within the next several months and completed by the end of 1982. As an interim measure, PSE&G was required to perform a preliminary design assessment of the Salem Unit 2 control room to identify significant human factors deficiencies and instrumentation problems. The NRC staff and its consultant, the Essex Corporation, followed up the PSE&G assessment with a five-day on-site control room review and PSE&G assessment audit. The review included the assessment of control and display panel layout, annunciator design, labeling of panel components, and useability and completeness of selected emergency procedures. The review/audit was performed by means of detailed inspection of the control panels, interviews with operators, and observation and videotaping of operators as they walked through selected emergency procedures.

Although our review identified some human factors deficiencies, in general we found that the control room was designed to promote effective and efficient operator actions. The controls and displays are functionally grouped and generally well integrated. Each functional group is clearly designated with labels of adequate readability. The audio alarm system is designed to provide a directional as well as tonal differentiation. The first out annunciators provide information to assist the operators in rapid diagnosis of system conditions. Console annunciators assist the operator in locating the appropriate controls and displays on the console. There is a consistent use of color coding in the control room and mimicking is employed in the areas of system safety monitors and station power. The Salem Unit 2 control room is separated from the Salem Unit 1 control room by two glass partitions and a central corridor. The separation of control room aids in reducing noise and control room traffic.

The more significant deficiencies identified during the control room review are as follows:

1. Annunciator Audible Alarms - The audible alarms for the overhead and console annunciators average approximately 3-5 dB(A) above

ambient noise levels. Established human engineering criteria require a minimum signal-to-noise difference of 20 dB(A) in at least one octave band between 200 and 5,000 Hz.

2. Lamp Test - The majority of indicator lights, legend lights and illuminated legend switches have no provision for lamp testing. A number of the legend lights serve as annunciators for critical system parameters, making lamp testing a mandatory design requirement.

3. Labeling - Magnetic labels are used for most of the modular components. Although this practice may facilitate component replacement, the potential for losing or mislocating labels on critical components unnecessarily increases the probability of operator error.

4. Emergency Procedures - Emergency procedures employed at Salem Unit 2 evidenced the following deficiencies:

   a. Type size is too small, increasing the probability of reading errors.

   b. There is excessive referencing of other procedures; in some cases, the instruction to reference was longer than the referenced provision.

5. Vertical Meter Failure - Vertical meters employed throughout the control room are designed such that failure of the meter input results in a mid-range indication. During critical activities, a failed meter could mislead the operator.

The above deficiencies are those which we believe could cause the operator to take erroneous actions under stressful conditions. These actions could initiate a transient or could exacerbate the operator's response to an abnormal event already underway. However, none of these deficiencies offer any significant risk to fuel loading and low power testing.

In order to correct these deficiencies, PSE&G and the staff have agreed that the following solutions will be implemented prior to escalation beyond five percent power:

1. Increase levels of audible alarms.

2. Install lamp test receptacle in console for testing control modules.

3. Permanently attach component labels.

4. Retype emergency operating procedures (EOP) with larger type and include referenced procedure within EOP.

5. Increase operator awareness of the mid-range failure.

In addition, several minor deficiencies (which offer no significant risk to full power operation) of the following nature were identified during the control room review.

1. <u>Annunciator Bulb Replacement</u> - Due to the location of the elevated annunciators, operators must stand on top of the incline surface on the rear of the console during bulb replacement. An overhead hand rail and nonskid surface on the console top should be provided to reduce the likelihood of the operator falling during bulb maintenance.

2. <u>Emergency Apparatus</u> - No emergency breathing apparatus is provided in the event of fire or other emergency conditions in the control room.

3. <u>Power Distribution Supervisory Lights</u> - Indicator lights lack lines of demarcation to delineate the various subsystems indicated on the panel. A number of lights employ a neon element covered with a translucent cap, making it difficult to distinguish light status.

4. <u>Operating Range Indications</u> - Vertical indicators are not coded to portray normal, marginal and out-of-tolerance operating ranges. This affects the operators' ability to readily identify plant status.

5. <u>Display Scaling</u> - Some displays do not optimize scale usage. For example, the indicator for the steam generator feedwater pumps is scaled from 0 to 1,400 PSIG; however, the operating range for this pump is 200-300 PSIG.

6. <u>Non-Standard Display Increments</u> - Displays employ non-standard increments (e.g., increments of 8.5 GPM on Cold Leg Injection). This practice increases workload during display interpolation, with an attendant increase in reading error.

7. <u>Strip Charts</u> - A number of deficiencies were noted in the design and location of various strip charts, such as;

a. The reactor coolant pump seal leak-off flow strip chart is ambiguous due to the use of a single scale for two pens recording on different ranges.

b. Strip charts on the vertical panel behind Console Panel No. 4 are not readable from the main operating area.

8. Annunciator Acknowledge - There are two pushbuttons located on the front of the main benchboard. The pushbuttons are not convenient to several primary operating stations, requiring the operator to leave his station to acknowledge an alarm. Also, annunciators for radiation monitoring cannot be acknowledged from the primary operating station. At least one more acknowledge switch should be provided.

In many cases the above deficiencies had been previously identified by PSE&G during its control room review, and in most cases plans are now in process to rectify these deficiencies. However, to ensure that additional modifications are made in the most efficient and effective manner to an already well designed control room, we will not require implementation of the minor design deficiencies until PSE&G has completed the detailed control room design review to be required of all operating reactors. As part of this design review, we will require PSE&G to evaluate the benefits of installing data recording and logging equipment in the control room to correct the deficiencies associated with strip chart recorders.

Item 2. Power Ascension Test Schedule

POSITION

The Office of Inspection and Enforcement should increase scrutiny of the power ascension test program to prevent any compromising of safety in view of the proposed expansion of startup test programs and the economic incentives to achieve the already delayed commercial operation of new plants.

DISCUSSION AND CONCLUSIONS

The licensee committed by letters dated February 8, and March 31, 1980 to perform special tests involving verification of natural circulation core cooling capability as part of the Salem Unit 2 low power test program. (See Section I.G of Part II to this report.) The senior resident inspector will witness the initial performance of these tests and as much of the normal startup tests as practicable. This effort will be augmented by IE Region I inspectors as necessary.

☆U.S. GOVERNMENT PRINTING OFFICE: 1980 620-269/94 1-3

NRC FORM 335 (7-77) U.S. NUCLEAR REGULATORY COMMISSION **BIBLIOGRAPHIC DATA SHEET**		1. REPORT NUMBER *(Assigned by DDC)* NUREG-0517 Supp. No. 4	
4. TITLE AND SUBTITLE *(Add Volume No., if appropriate)* Supplement No. 4 to the Salem Nuclear Generating Station, Unit 2 Safety Evaluation Report		2. *(Leave blank)*	
		3. RECIPIENT'S ACCESSION NO.	
7. AUTHOR(S)		5. DATE REPORT COMPLETED MONTH April YEAR 1980	
9. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS *(Include Zip Code)*		DATE REPORT ISSUED MONTH April YEAR 1980	
		6. *(Leave blank)*	
		8. *(Leave blank)*	
12. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS *(Include Zip Code)* U. S. Nuclear Regulatory Commission Washington, D. C. 20555		10. PROJECT/TASK/WORK UNIT NO.	
		11. CONTRACT NO.	
13. TYPE OF REPORT	PERIOD COVERED *(Inclusive dates)* January 1, 1979 - April 18, 1980		
15. SUPPLEMENTARY NOTES Docket No. 50-311		14. *(Leave blank)*	

16. ABSTRACT *(200 words or less)*

Public Service Electric and Gas Company filed an application for operating licenses on August 27, 1971 for the Salem Nuclear Generating Station, Units 1 and 2. Unit 1 of the Salem Station was issued an operating license on August 23, 1976. The Safety Evaluation Report and Supplements 1 and 2 issued October 11, 1974, June 28, 1976, and August 13, 1976, respectively concern the review of Units 1 and 2. Supplement No. 3, issued December 29, 1978, applies only to Unit 2, although many issues are common to both units. It provides an evaluation of the additional information submitted by the applicants since the issuance of Supplement No. 2. This supplement addresses the requirements for fuel loading and conducting low power testing of Salem Nuclear Generating Station, Unit 2 up to a power level of five percent.

17. KEY WORDS AND DOCUMENT ANALYSIS	17a. DESCRIPTORS	
17b. IDENTIFIERS/OPEN-ENDED TERMS		
18. AVAILABILITY STATEMENT	19. SECURITY CLASS *(This report)*	21. NO. OF PAGES
	20. SECURITY CLASS *(This page)*	22. PRICE $

NRC FORM 335 (7-77)

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

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

POSTAGE AND FEES PAID
U.S. NUCLEAR REGULATORY
COMMISSION

U.S. MAIL