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to NUREG-75/034

# Safety Evaluation Report
## related to the operation of Joseph M. Farley Nuclear Plant Unit 2

Docket No. 50-364

Alabama Power Company
Supplement No. 4

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U.S. Nuclear Regulatory Commission

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## 1.0 INTRODUCTION AND GENERAL DISCUSSION

### 1.1 Introduction

On May 2, 1975, the Nuclear Regulatory Commission (Commission) issued its Safety Evaluation Report in the matter of Alabama Power Company's application to operate the Joseph M. Farley Plant Units 1 and 2. The Safety Evaluation Report (SER) was supplemented by Supplement Nos. 1, 2, and 3 which described the resolution of outstanding issues.

On June 25, 1977, Facility Operating License NPF-2 was issued for Farley Unit 1, with several license conditions covering outstanding items at the time of issuance. Fifteen amendments to NPF-2 have been issued to satisfy license conditions and resolve other issues that arose since date of issuance.

Subsequent to the issuance of SER Supplement No. 3 in June 1977, Final Safety Analysis Report (FSAR) Amendment Nos. 67 through 74 have been filed to document changes to Unit 1 and Unit 2 design bases and analyses. Analyses of the effect on Unit 1 operation of significant changes in these FSAR amendments have been provided in letters from the licensee pursuant to 10 CFR 50.59. Our evaluation of the effect on Unit 2 is contained in this supplement.

Following the Three Mile Island Unit 2 (TMI-2) accident, the Commission "paused" in its licensing activities to assess the impact of the accident. During this "pause" the recommendations of several groups established to investigate the lessons learned from TMI-2 became available. All available recommendations were correlated and assimilated into a "TMI Action Plan" now published as NUREG-0660, entitled "NRC Action Plan Developed as a Result of the TMI-2 Accident."

Our review of TMI-2 requirements is based on Commission guidance provided in S. Chilk memorandum of June 5, 1980 (COMJA-80-23) for current operating license applications; the requirements are derived from NRC's Action Plan (NUREG-0660) and are found in NUREG-0694, "TMI-Related Requirements for New Operating Licenses." The Farley Nuclear Plant Unit 2 was measured against the NRC regulations as augmented by these requirements.

The initial response of the applicant to our new requirements was provided in a report entitled, "Response to TMI-2 Action Plan," dated June 20, 1980. Chapter 22 of this supplement addresses our review and evaluation of the applicant's response. It replaces Chapter 22, "Conclusions," of the May 1975 Safety Evaluation Report. The conclusions for this supplement are provided in Chapter 23.

As part of our review of the application against the Commission's regulations, we requested the applicant to verify that the Farley Plant meets the applicable requirements in 10 CFR Parts 20, 50, and 100. The applicant responded to this request with a letter dated August 25, 1980, which contained an in-depth comparison of the application with the regulations.

Accordingly, the applicant stated that the Farley Plant complies with the applicable regulations with the exception of those instances where specific exemptions have been justified by the applicant and approved by NRC. Based on our review of the applicant's response and our audit of their application for an operating license with regard to all applicable regulations of the Commission, we have determined that the Joseph M. Farley Plant, Unit 2 will operate in conformity with the provisions of the Act, and the rules and regulations of the Commission, and that there is reasonable assurance that the activities that would be authorized by the operating license for this plant can be conducted without endangering the health and safety of the public.

Chapters 5, 6, 7, 8, 9, 11, 12, 13, 14, 15, and 17 of this supplement address our review and evaluation of non-TMI issues that have arisen since the issuance of SER Supplement No. 3 in June 1977. Each of the sections of these chapters is numbered the same as corresponding sections in the Safety Evaluation Report. Except where noted, the material herein supplements material in the SER and Supplement Nos. 1, 2 and 3.

Chapter 22 of this supplement addresses our review and evaluation of applicant's response to the requirements resulting from the TMI-2 accident. The conclusions of this supplement are given in Chapter 23.

Appendix A is a continuation of the chronology of our principal actions related to the processing of the application.

On the basis of staff review, we conclude that the Joseph M. Farley Plant, Unit 2 may be issued a license for fuel loading, zero power physics testing and, after further Commission approval, low power testing up to 5 percent of full power in accordance with the technical specifications without undue risk to the health and safety of the general public.

## 1.7 Outstanding Issues

In Supplement No. 3 to the SER, we identified five (5) open items that were made conditions in the Unit 1 Operating License (NPF-2), issued June 25, 1977. Since that time, three of these conditions have been removed by Amendments to the Unit 1 license. Our evaluation and resolution of these items for Unit 2 are discussed in the sections of this supplement as indicated below.

(1) Low temperature overpressure mitigation system (Section 5.4.2)
(2) Assurance of adequate performance of the ECCS during recirculation following a LOCA (Section 6.3.3)
(3) Installation of environmentally qualified pressure transmitters (Section 7.7)

Two Unit 1 license conditions remain in effect and will be included in the Unit 2 license or technical specifications.

(1) NRC evaluation of lifting devices attached to the spent fuel cask prior to handling the cask.
(2) NRC evaluation of plant performance with less than three operating reactor coolant pumps prior to operating with that condition.

In Supplement No. 3 to the SER, we also identified two generic issues. Our status of review of these issues is in the sections indicated below.

(1) Environmental qualification of safety-related equipment (Section 7.7.2)

(2) Anticipated transients without scram (Section 5.4.1)

All the new areas that have arisen since issuance of Supplement No. 3 to the SER, including TMI issues, have been satisfactorily resolved for fuel loading and low power testing except the following items, which will be license conditions.

(1) Prior to exceeding zero power (i.e., that required for physics tests), redundant power supplies will be installed on auxiliary feedwater flow control valves (II.E.1.2, Section 22.2).

(2) Prior to conducting the augmented low power tests, applicant must receive NRC approval of its safety analysis report on the conduct of the tests (I.G.1 Section 22.2)

### 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 safety generic issues in connection with our licensing proceedings. Those requirements are applicable to the Joseph M. Farley Nuclear Plant, Unit 2 application.

Appendix C to this supplement presents information for the Joseph M. Farley Nuclear Plant, Unit 2 application in conformance with the Appeal Board decision enunciated in ALAB-444.

# 3.0 DESIGN CRITERIA FOR STRUCTURES, COMPONENTS, EQUIPMENT AND SYSTEMS

## 3.9 Mechanical Systems and Components

### 3.9.2 Reactor Internals Design, Analysis and Testing

Degradation of guide thimble tube walls has been observed during post-irradiation examinations of irradiated fuel assemblies taken from several operating pressurized water reactors. 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 guide thimble tube wall, a fretting wear of the wall occurs. Significant wear has been found to be confined to the relatively soft Zircaloy-4 guide thimble tubes because the control rod claddings -- stainless steel for Westinghouse designs -- provide a relatively hard wear surface. The extent of the observed wear is both time and design dependent and has, in some non-Westinghouse designs, 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 condition 1-4 events and (2) hinder scramability.

As a part of the staff's review of the susceptibility and impact of guide thimble tube wear in Westinghouse plants, two meetings were held with Westinghouse and information was submitted by Westinghouse (Letter from T. M. Anderson to H. R. Denton, NRC, April 29, 1980) and Alabama Power Company (Letter from F. L. Clayton to H. R. Denton, May 12, 1980). This information consisted of (a) guide thimble tube wear measurements taken on irradiated fuel assemblies from Point Beach, Units 1 and 2 (two-loop plants using 14x14 fuel assemblies); (b) 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; and (c) responses to staff questions.

Westinghouse believes that their fuel designs will experience less wear than that reported in some other NSSS 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 their 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) their guide thimble tubes will be able to fulfill their design functions.

The staff concluded that the Westinghouse analysis probably accounts for all of the major variables that control this wear process. Nevertheless, because of the complexities and uncertainties in (a) determining contact forces, (b) surface-to-surface wear rates, (c) forcing functions, and (d) extrapolations of these variables to the 17x17 fuel assembly design (such as that to be used in Farley, Unit 2), the staff concluded that a surveillance program should be performed. For acceptability, the minimum objective of such program was to demonstrate that there is no occurrence of hole formation in rodded guide thimble tubes.

To satisfy this request for confirmation of the Westinghouse analytical predictions, a cooperative owners group was established which is now sponsoring a program to obtain post-irradiation examination (PIE) data from the Salem, Unit 1 facility (four-loop plant using 17x17 fuel assemblies). In the fall of 1980, this PIE program will examine all guide thimble tubes in six-rodded fuel assemblies having either one or two cycles of burnup. On the basis of the data and analyses mentioned above and the confirmation surveillance program that will be performed, we conclude that the guide thimble tube walls meet the applicable requirements of General Design Criteria 1, 2, 4 and 10, and are therefore acceptable.*

### 3.9.3 Components Designated ASME Code Classes 2 and 3

As a part of a program of performing an independent confirmatory piping analysis for plants being reviewed for an operating license. We contracted with Battelle Pacific Northwest Laboratories to perform an independent confirmatory stress analysis of the Farley-2 "A" main steam line. The purpose of this analysis was to determine if the calculated stresses in the as-built piping were less than the applicable American Society of Mechanical Engineers (ASME) Code stress allowables. This analysis also served as a random check of the applicant's ability to model its piping systems and use its computer programs.

The Farley-2 "A" main steam line is an ASME Code Class 2 line. We analyzed this line for the loads due to pressure, deadweight, thermal expansion, and the safe shutdown earthquake in accordance with the rules of the 1971 Edition of the ASME Code, Paragraph NC-3652. We found that there is reasonable agreement between our calculations and those of the applicant and that the main steam line stresses are within Code allowable stress.

We conclude that the design of the main steam line complies with the applicable ASME Code requirements, meets the applicable requirements of General Design Criteria 1, 2 and 4,* and is therefore acceptable.

### 3.9.4 Inservice Testing of Pumps and Valves

By letter dated March 12, 1980, the applicant submitted a description of its proposed inservice testing program for pumps and valves. The program includes both baseline pre-service 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.

*General Design Criteria as used in this supplement refer to those in Appendix A to 10 CFR Part 50: Criterion 1, "Quality Standards and Records"; Criterion 2, "Design Basis for Protection Against Natural Phenomena"; Criterion 4, "Environmental and Missile Design Bases"; Criterion 10, "Reactor Design."

The date of the applicant's construction permit (August 16, 1972) places this plant under 10 CFR 50.55a(g)(2), which requires compliance with the 1971 Edition through the Winter 1971 Addenda of Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code. Inservice testing requirements for pumps and valves were not included in the Code until the Summmer 1973 addenda, well after the design of the plant was mostly complete. Paragraph 50.55a(g)(4)(i) requires that the applicant comply with the latest edition and addenda of the Code incorporated by reference in Paragraph 56.55a(b) on the date 12 months prior to the date of issuance of the operating license. In accordance with this regulation, the 1974 Edition through 1975 Addenda is required for inservice testing of pumps and valves for Farley Unit 2. The applicant cannot in all cases meet the requirements of the 1974 Edition through the Summer 1975 Addenda of Section XI and has requested relief from certain Code requirements as discussed below.

The applicant proposes that the period for which the program is applicable be the 120-month period commmencing with the start of commercial operation.

Based on our preliminary review, we find that it is impractical within the limitations of design, geometry, and accessibility for the applicant to meet certain of the ASME 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)(4) and (g)(6)(i), the relief that the applicant has requested from pump and valve testing requirements of the ASME Code is granted for that portion of the initial 120 month period during which we complete our confirmatory review. The granting of this relief from the Code requirements is authorized by law and will not endanger life or property or the common defense and security and is otherwise in the public interest. The staff's review of the inservice testing program will continue throughout the first inservice testing period of 20 months.

Since the applicant will comply with Section XI of the ASME Boiler and Pressure Vessel Code and the Farley Unit 2 Technical Specifications, we find the Farley Unit 2 inservice testing program for pumps and valves to be acceptable.

### 3.10 Seismic Qualification of Cateogry I Mechanical and Electrical Equipment

In Section 7.7 of the Safety Evaluation Report (SER) dated May 2, 1975, we stated that the applicant's seismic qualification of balance of plant (BOP) instrumentation and electrical equipment complied with IEEE Standard 344-1971, "Guide for Seismic Qualification of Class 1E Electrical Equipment for Nuclear Power Generating Stations," and was acceptable. Furthermore, in Section 3.9.1 of the same SER we concluded that the dynamic test and analysis procedures utilized by the applicant provide reasonable assurance that in the event of an earthquake at the site, the seismic Category I mechanical equipment will continue to function during and after the seismic event. In Supplement 3 to this SER we further concluded that the seismic qualification of the nuclear steam supply system (NSSS) instrumentation and electrical equipment was acceptable.

Since that time, our requirements with respect to seismic qualification have changed. Standard Review Plan (SRP) Section 3.10 has been published. SRP 3.10 specifies criteria which when conformed with satisfy the applicable portions of GDC 2 of Appendix A to 10 CFR 50. This SRP section references Regulatory Guide 1.100, "Seismic Qualification of Electric

Equipment for Nuclear Power Plants," and IEEE Standard 344-1975, "IEEE Recomended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations." The principal change in our criteria is to require consideration of equipment multi-mode response and biaxial coupling effects. In view of these changes we considered it prudent to further review the Farley 2 equipment qualification program against SRP Section 3.10, to determine whether the original tests and analyses were adequate. Our previous review of Westinghouse equipment for the Farley Plant considered the effects of multi-mode response and biaxial coupling, and found this equipment adequately qualified. This evaluation addresses the qualification of BOP electrical and mechanical equipment.

Our Seismic Qualification Review Team (SQRT) performed a review at the plant site on July 7-10, 1980 to determine whether the qualification of the equipment, as installed in Farley 2, performed in accordance with the procedures of IEEE Standard 344-1971 could meet current licensing criteria as described in SRP Section 3.10. During this review we evaluated a representative sample of thirty-four pieces of Seismic Category I mechanical, instrumentation, and electrical equipment. Our review uncovered relatively few pieces of equipment for which it was not clear that the seismic qualification was acceptable in the light of current licensing criteria. For example, the battery charger in the service water building was mounted flat on the test table, while it is cantilevered off the wall in the field. Also, the solenoid valve in the river water building is field mounted in such a way that it may be susceptible to low frequency (below 20 hertz) input, yet the test was apparently conducted only for a frequency range beyond 20 hertz. The details of these shortcomings and others in the equipment qualification are described in the report of our July 7-10, 1980 trip to the plant. For these few items, the applicant has committed to submit additional information, clarification, and resolution for our review prior to approval of full power operation. In addition, the SQRT has requested, and the applicant has provided, pertinent documents as well as test and analysis reports for five (5) pieces of equipment in order that we can conduct a followup in-depth confirmatory review.

Based on the results of the review of installed equipment by the Seismic Qualification Review Team, we conclude that there is no severe discrepancy in the equipment qualification program with respect to SRP 3.10 criteria, and there is reasonable assurance that low power operation of the plant can be permitted at this time without endangering public health and safety. We will complete our confirmatory in-depth review and require the applicant to clarify the seismic qualification of the equipment identified in our trip report prior to full power operation of Farley 2.

# 5.0 REACTOR COOLANT SYSTEM

## 5.2 Integrity of the Reactor Coolant Pressure Boundary

### 5.2.1 Materials

General Design Criterion 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," Appendix A, 10 CFR Part 50, requires that the reactor coolant pressure boundary be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions the boundary behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized. General Design Criterion 32, "Inspection of Reactor Coolant Pressure Boundary," Appendix A, 10 CFR Part 50, requires that the reactor coolant pressure boundary be designed to permit an appropriate material surveillance program for the reactor pressure boundary.

We have reviewed the materials selection, toughness requirements, and extent of materials testing in accordance with the above General Design Criteria. The ferritic materials of Farley Unit No. 2 were specified to meet the toughness requirements of the 1968 Edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, "Rules for Construction of Nuclear Power Plant Components."

Appendix G, "Fracture Toughness Requirements," and Appendix H, "Reactor Vessel Material Surveillance Requirements," of 10 CFR Part 50, specify the fracture toughness requirements for the ferritic materials of the reactor coolant pressure boundary. The ferritic materials of Farley Unit No. 2 were qualified by impact testing in accordance with the 1968 ASME Code, Section III, and pursuant to paragraph 50.55a(g)(2) of 10 CFR Part 50, we have evaluated the reactor vessel ferritic materials in accordance with the 1968 Edition of the ASME Code through 1970 Summer Addenda.

#### Compliance with Appendix G, 10 CFR Part 50

We have evaluated the information in the applicant's FSAR to determine the degree of compliance with the fracture toughness requirements of Appendix G, 10 CFR Part 50. Our evaluation indicates that the applicant has met all requirements of Appendix G, 10 CFR Part 50, except for the following paragraphs: I.A and IV.A.2.a, which will remain open until the applicant supplies further data and analysis; and III.B.4 and IV.B, for which the applicant has supplied sufficient data and analyses to justify an exemption.

1. Paragraph I.A requires the applicant to demonstrate to the Commission on an individual case basis the adequacy of fracture toughness in any ferritic material having a specified minimum yield strength over 50 ksi. The applicant must address both the generic requirements of Appendix G, Section III, of the ASME Code, and also the specific fracture toughness requirements of Appendix G, 10 CFR Part 50. According to the FSAR, SA533 Class 2 and SA508 Class 2a steels are used in the pressurizer. The applicant has identified the specific components in which these high strength materials are used and

has provided data to demonstrate compliance with the Charpy impact energy requirements of Appendix G, 10 CFR Part 50. However, the applicant has not sufficiently addressed the generic requirements for high strength materials.

According to Appendix G, Section III of the ASME Code, the applicant must supply fracture mechanics data (similar to the $K_{ID}$ data referenced in WRCB-175) from at least three heats of the material and from a sufficient number of specimens to cover the temperature range of interest for any ferritic steel having a specified minimum yield strength greater than 50 ksi. All data must be equal to or above the $K_{IR}$ (reference) curve of Figure G-2210-1 of Appendix G, Section III, ASME Code. The applicant also must demonstrate that the calculated stress intensity factors are lower than the reference stress intensity factors ($K_{IR}$) by the margins specified by Appendix G of the ASME Code and as required by Paragraph IV.A.2.a, Appendix G, 10 CFR Part 50, to provide adequate safety for normal operation of the ferritic pressure boundary of the pressurizer.

We conclude that the applicant has not provided necessary and sufficient information to demonstrate full compliance with Paragraphs I.A and IV.A.2.a. The applicant has stated that the information necessary to fully satisfy this requirement will be provided to us by September 30, 1980 and the staff will condition the license accordingly. The applicant has provided sufficient information to allow us to determine that prior to normal full power operation, the safety margins required for low power operation will be achieved and maintained. On this basis, we conclude that low power operation is acceptable. We will complete our review prior to full power operation to confirm that adequate safety margins will also be maintained during normal operation, including operational transients, in compliance with Paragraphs I.A and IV.A.2.a of Appendix G to 10 CFR Part 50.

2. Paragraph III.B.4 requires that the testing personnel shall be qualified by training and experience and should be competent to perform the tests in accordance with written procedures. For Farley Unit No. 2 component testing, no written procedures were in existence as required by the later regulation; however, the applicant has supplied sufficient information to demonstrate that the intent of Paragraph III.B.4 has been met. The applicant has stated that individuals who conducted the testing were qualified by schooling, training, and years of experience and were certified by qualified supervisory personnel. Because these tests are relatively routine in nature and are continually being performed in the laboratory, we conclude that it is unlikely that the tests were conducted improperly. Consequently, we conclude that an exemption for not performing the tests in accordance with written procedures is justified.

3. Paragraph IV.B requires that the reactor vessel beltline materials have a minimum unirradiated upper shelf energy of 75 ft-lbs in order to provide adequate margin for deterioration from irradiation. In weld seam 10-923, two of nine specimens tested had impact energies below 75 ft-lbs at a test temperature of 10 degrees Fahrenheit; no additional testing was conducted at higher temperatures to define upper shelf energy. The applicant has proposed a correlation between Charpy impact energy and temperature for welds fabricated with the same type of wire and lot of flux as used in weld seam 10-923 of Farley Unit No. 2. We have evaluated the applicant's additional data, which includes a broad temperature range over the lower shelf, transition and upper shelf temperature regions and have found that:

(a) weld seam 10-923 is represented by the additional data;

(b) the additional data can be used to extrapolate to the upper shelf for weld seam 10-923; and

(c) the minimum upper shelf energy is at least 100 ft-lbs.

Based on this additional information and our evaluation, we conclude that an exemption to Paragraph IV.B, Appendix G, 10 CFR Part 50, is justified.

Compliance with Appendix H, 10 CFR Part 50

The toughness properties of the reactor vessel beltline materials will be monitored throughout the service life of Farley Unit No. 2 by a materials surveillance program that must meet the requirements of ASTM Standard E-185-73, "Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels," and Appendix H, 10 CFR Part 50. We have evaluated the applicant's information for degree of compliance to these requirements and have concluded that the applicant has met all requirements of Appendix H, 10 CFR Part 50, except for Paragraph II.B, for which sufficient information has been supplied to justify an exemption.

Paragraph II.B requires the beltline region of the reactor vessel to be monitored by a surveillance program complying with ASTM Standard E-185-73. According to this standard the base metal and weld metal to be included in the program should represent the material that may limit the operations of the reactor during its lifetime. This selection is based on initial transition temperature, upper shelf energy level, and estimated increase in transition temperature considering chemical composition (copper and phosphorus) and neutron fluence.

According to our evaluation, plate B7212-1 and weld seam 11-923 are the most limiting base and weld materials, respectively; the base plate B7212-1 is predicted to be the more limiting of the two. The Farley Unit No. 2 surveillance program contains material from base plate B7212-1 and weld seam 19-923B. Because weld seam 19-923B is not the most limiting weld in the reactor vessel beltline region, the applicant's material surveillance program is not in full compliance with Appendix H, 10 CFR Part 50. To have an acceptable surveillance program for Farley Unit No. 2, the applicant must use the following analysis for every capsule removed and tested.

During the plant's life the applicant must recalculate the pressure-temperature operating limits based on the greater of the following: (a) the actual shift in reference temperature for plate B7212-1 as determined by impact testing, or (b) the predicted shift in reference temperature for weld seam 11-923 as determined by Regulatory Guide 1.99, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials."

Although material from the most limiting weld seam, 11-923, is not contained in the Farley Unit No. 2 materials surveillance program, we have found that an exemption to Paragraph II.B of Appendix H, 10 CFR Part 50, is justified for the following reasons: (1) the applicant has included in the surveillance program the beltline material predicted to be most limiting; and (2) we have conservative methods of analysis, contained in Regulatory Guide 1.99, to determine the radiation characteristics of the limiting beltline weld. For these reasons, we conclude that the integrity of the reactor coolant pressure boundary will be ensured during all normal plant operations and anticipated operational occurrences, and thus, the exemption to Paragraph II.B, Appendix H, 10 CFR Part 50, is justified.

Conclusion

Based on our review, we conclude that it is impractical for the applicant to meet Paragraphs III.B.4 and IV.B of Appendix G and Paragraph II.B of Appendix H. Imposition of requirements in these paragraphs would result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. The granting of exemption from these paragraphs is authorized by law and will not endanger life or property or the common defense or security and is otherwise in the public interest. Therefore, pursuant to 10 CFR 50.12(a), exemptions from the requirements of these paragraphs are granted. Appendix G, "Protection Against Non-Ductile Failure," Section III of the ASME Boiler and Pressure Vessel Code, will be used with fracture toughness test results required by Appendices G and H, 10 CFR Part 50, to calculate the reactor coolant pressure boundary pressure-temperature limits for Farley Unit No. 2.

The fracture toughness tests required by the ASME Code and Appendix G, 10 CFR Part 50, will provide reasonable assurance that adequate safety margins against the possibility of non-ductile behavior or rapidly propagating fracture can be established for all pressure retaining components of the reactor coolant pressure boundary. The use of Appendix G, Section III of the ASME Code, as a guide in establishing safe operating procedures, and use of the results of the fracture toughness tests performed in accordance with the ASME Code and NRC regulations, will provide adequate safety margins during operating, testing, maintenance, and anticipated transient conditions. Compliance with these Code provisions and NRC regulations constitutes an acceptable basis for satisfying the requirements of General Design Criterion 31, "Fracture Prevention of Reactor Coolant Pressure Boundary."

The material surveillance program, required by Appendix H, 10 CFR Part 50, will provide information on material properties and the effects of irradiation on the material properties so that changes in the fracture toughness of material in Farley Unit No. 2's reactor vessel beltline region caused by neutron radiation can be properly assessed, and adequate safety margins against the possibility of vessel failure can be provided. Compliance with ASTM E-185-73 and Appendix H, 10 CFR Part 50, satisfies the requirements of General Design Criterion 31 and General Design Criterion 32, "Inspection of Reactor Coolant Pressure Boundary."

5.2.2 Pressure-Temperature Limits

Appendix G, "Fracture Toughness Requirements," and Appendix H, "Reactor Vessel Material Surveillance Program Requirements," 10 CFR Part 50, describe the conditions that require pressure-temperature limits for the reactor coolant pressure boundary and provide the general bases for these limits. These appendices specifically require that pressure-temperature limits must provide safety margins for the reactor coolant pressure boundary at least as great as the safety margins recommended in the ASME Boiler and Pressure Vessel Code, Section III, Appendix G, "Protection Against Non-Ductile Failure." Appendix G, 10 CFR Part 50, requires additional safety margins whenever the reactor core is critical, except for low-level physics tests.

The following pressure-temperature limits imposed on the reactor coolant pressure boundary during operation and tests are reviewed to ensure that they provide adequate safety margins against non-ductile behavior or rapidly propagating failure of ferritic components as required by General Design Criterion 31:

1. Preservice hydrostatic tests,
2. Inservice Leak and Hydrostatic Tests,
3. Heatup and cooldown operations, and
4. Core operation.

Appendices G and H, 10 CFR Part 50, require the applicant to predict the shift in reference temperature due to neutron irradiation. This shift must be based on neutron radiation damage predictions at least as conservative as those of Regulatory Guide 1.99, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials." The initial set of pressure-temperature limits is based on this predicted shift; however, once in service, the pressure-temperature limits must be revised to reflect the actual neutron radiation damage as determined from the results of the reactor vessel materials surveillance program.

The information submitted by the applicant is based on radiation damage prediction curves supplied by Westinghouse Electric Corporation. At high neutron fluences, these curves are not as conservative as those of Regulatory Guide 1.99 and, therefore, are not acceptable. As a consequence, we do not find the proposed pressure-temperature limit curves (Technical Specifications Figures 3.4-2 and 3.4-3) acceptable for use prior to operation and the acquisition of data from irradiated samples from Farley beltline materials.

The proposed heatup and cooldown pressure-temperature limits apply to the first 12 effective full power years. According to data from Farley Unit No. 2's FSAR, we find the proposed temperatures to be approximately [illegible] degrees Fahrenheit too low.

Either of the following steps may be taken to correct this deficiency: (1) recalculate the pressure-temperature limits for 12 effective full power years, using radiation damage predictions at least as conservative as those of Regulatory Guide 1.99; or (2) change the applicable period for the limits presented in the Technical Specifications from 12 to 5 effective full power years. The latter course of action is based on the following assumptions: (a) the reactor vessel intermediate shell material contains 0.20 percent by weight of copper and 0.018 percent by weight of phosphorus; (b) the initial $RT_{NDT}$ is (-10) degrees Fahrenheit; (c) no margin for instrument error is included in the limits; and (d) the radiation damage prediction of Regulatory Guide 1.99 is used.

Since the proposed pressure-temperature limits are acceptable for five effective full power years, we will limit their use to that interval in the Farley 2 Technical Specifications. We will also delete Figure B3/4.4-2 of the Technical Specification Bases Section 3/4.4-9. This figure contains the Westinghouse radiation prediction curves. For operation after five effective full power years, the pressure-temperature limits must be recalculated based on data from irradiated samples of Farley reactor vessel material or other methods approved by the staff.

The pressure-temperature limits to be imposed on the reactor coolant system for all operating and testing conditions to ensure adequate safety margins against nonductile or rapidly propagating failure must be in conformance with established criteria, codes, and standards acceptable to the staff. The use of operating limits based on these criteria, as defined by applicable regulations, codes, and standards, provides reasonable assurance that nonductile or rapidly propagating failure will not occur, and constitutes an acceptable basis for satisfying the applicable requirements of General Design Criterion 31.

5.3 Integrity of the Reactor Vessel

We have reviewed the FSAR sections related to the reactor vessel integrity of Farley Unit No. 2. Although most areas are reviewed separately in accordance with other review plans, reactor vessel integrity is of such importance that a special summary review of all factors relating to reactor vessel integrity is warranted.

We have reviewed the information in each area to ensure that it is complete and that no inconsistencies exist that would reduce the certainty of vessel integrity. The areas reviewed are:

1. Design (Section 5.2.1 of this Supplement)
2. Materials of construction (Section 5.2.1 of this Supplement)
3. Fabrication methods (Section 5.2.1 of this Supplement)
4. Operating conditions (Section 5.2.2 of this Supplement)

We have reviewed the above factors contributing to the structural integrity of the reactor vessel and conclude that the applicant has complied with Appendices G and H, 10 CFR Part 50, except for Paragraphs III.B.4 and IV.B of Appendix G, and Paragraph II.B of Appendix H. However, the applicant has supplied sufficient information to justify exemptions to these paragraphs, as summarized below.

1. Paragraph III.B.4, Appendix G, requires the applicant to conduct impact testing according to specific written procedures. Although this was not done for Farley Unit No. 2 impact tests, the applicant has supplied sufficient information to demonstrate that the tests were conducted correctly, and therefore, we have concluded that an exemption to Paragraph III.B.4, Appendix G, is justified.

2. The applicant has supplied data and analyses for welds having the same weld wire and flux combination as weld seam 10-923 to demonstrate that weld seam 10-923 has a minimum upper shelf energy of at least 75 ft-lbs, and therefore, we conclude that an exemption to the Charpy impact test requirement of Paragraph IV.B, Appendix G, is justified.

3. Paragraph II.B, Appendix H, details the requirements for selecting test specimens for the materials surveillance program. The materials in Farley Unit No. 2's surveillance program together with methods for predicting radiation damage provide sufficient information for us to conclude that an exemption to Paragraph II.B, Appendix H, is justified.

Based on our review, we conclude that it is impractical for the applicant to meet Paragraphs III.B.4 and IV.B of Appendix G and Paragraph II.B of Appendix H. Imposition of requirements in these paragraphs would result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. The granting of exemption from these paragraphs is authorized by law and will not endanger life or property or the common defense or security and is otherwise in the public interest. Therefore, pursuant to 10 CFR 50.12(a), exemptions from the requirements of these paragraphs are granted.

We have reviewed all factors contributing to the structural integrity of the reactor vessel and conclude there are no special considerations that make it necessary to consider potential reactor vessel failure for Farley Unit No. 2.

### 5.4 Reactor Coolant System Overpressure Protection

#### 5.4.1 Anticipated Transients Without Scram

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 of 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 Farley 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 Farley 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 published as NUREG-0460, Volume 4, in March 1980.

We plan to present our recommendations on anticipated transients without scram to the Commission, 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. Farley Unit 2 would, of course, be subject to the Commission decision in this matter. The following discusses the bases for operation of Farley Unit 2 until final resolution of anticipated transients without scram is achieved.

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 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:

(1) An emergency operating procedure be developed for 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 rool with emphasis on alarms not processed through the electrical portion of the reactor scram system.

(2) The emergency operating procedures describe actions to be taken 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. These actions should also include prompt initiation of 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 Farley Unit 2 plant based on our understanding of the plant response to postulated anticipated transient without scram events.

In response to our letter dated June 13, 1980, the applicant has provided emergency operating procedure FNP-2-EOP-15.0, "Anticipated Transients Without Trip" by its letter dated June 30, 1980. We are currently reviewing this procedure and will obtain any revisions needed to make it acceptable prior to full power operation. We have concluded that the plant can be safely operated for low power testing because of the expected slow plant response to relevant anticipated transient without scram events at power levels not exceeding five percent.

### 5.4.2 Low Temperature Overpressure Mitigation System

By letter dated December 29, 1976 the Commission requested an evaluation of the Farley Nuclear Plant to determine susceptibility to overpressurization events at relatively low reactor coolant temperatures (less than 310°F). An overpressurization event is a transient that results in a pressure greater than the limiting pressure in technical specifications which are based on requirements of Appendix G to 10 CFR 50. We also requested an analysis of possible events and a description of systems and procedures that would reduce the likelihood and consequences of such events. By letter dated September 6, 1978 and subsequent letters, dated November 3, 9 and 17, 1978 and January 4, March 21, and April 17, 1979, applicant provided a description of an overpressure mitigation system and its expected performance and technical specifications for operability and surveillance. The evaluation is applicable to both Units 1 and 2.

The overpressure mitigation system uses the residual heat removal system relief valves. Technical specifications require that the residual heat removal system isolation valves must be open and the relief valves operable (or a reactor coolant system vent must be open) when reactor coolant temperature is less than 310°F. Technical specifications also specify conditions for which a reactor coolant pump can be started to minimize the occurrence of overpressurization events. Alarms are included in the design to alert the operator if the residual heat removal system isolation valves are not fully open and if an overpressurization event occurs.

We reviewed the system and associated technical specifications and transmitted our evaluation by a letter to the applicant dated July 31, 1979. We concluded that the overpressure mitigation system meets the applicable requirements of Appendix G to 10 CFR Part 50 and is therefore acceptable. Acceptable technical specifications for Unit 1 were also transmitted by our July 31, 1979 letter. The system and associated technical specifications will be completed for Unit 2 prior to fuel loading.

## 5.5 Pump Flywheel Integrity

General Design Criterion 4, "Environmental and Missile Design Bases," of Appendix A, 10 CFR Part 50, requires that nuclear power plant structures, systems, and components important to safety be protected against the effects of missiles that might result from equipment failures. Because flywheels have large masses and rotate at speeds of approximately 1200 revolutions per minute during normal operation, a loss of flywheel integrity could result in high energy missiles and excessive vibration of the reactor coolant pump assembly. The safety consequences could be significant because of possible damage to the reactor coolant system, the containment, or the engineered safety features. Adequate margins of safety and protection against the potential for damage from flywheel missiles can be achieved by the use of suitable material, adequate design, and inspection.

The reactor coolant pumps have been designed for a speed 125% that of the normal synchronous speed of the motor (approximately 1500 rpm). The minimum speed for ductile failure is estimated to be much higher than 125% of operating speed for flywheels of the design used at Farley Unit No. 2. According to Section 5.2.6.1 of the FSAR, the material used to manufacture the pump flywheels is SA-533 Grade B Class 1 steel plate. The applicant has supplied data and analysis to demonstrate that the Charpy upper shelf energy level in the "weak" direction is no less than 50 ft-lbs and also that the NDTT of the flywheel material is no higher than +10 degrees Fahrenheit. Thus, with the lowest design operating temperature being 110 degrees Fahrenheit, the normal operating temperature of the pump flywheel will be at least 100 degrees Fahrenheit above the $RT_{NDT}$ which satisfies the acceptance criteria for fracture toughness of Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity."

Based upon our evaluation, we conclude that the applicant is in compliance with NRC Regulatory Guide 1.14. Compliance with the recommendations of NRC Regulatory Guide 1.14 constitutes an acceptable basis for satisfying the requirements of General Design Criterion 4, "Environmental and Missile Design Basis."

## 5.7 Inservice Inspection Program

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

General Design Criterion 32, "Inspection of Reactor Coolant Pressure Boundary," Appendix A of 10 CFR Part 50, requires, in part, that components which are part of the reactor coolant pressure boundary be designed to permit periodic inspection and testing of important areas and features to assess their structural and leaktight integrity.

To ensure that no deleterious defects develop during service, selected welds and weld heat-affected zones [illegible] inspected periodically at Joseph M. Farley, Unit No. 2. The design of the ASME Code Class 1 components of the reactor coolant pressure boundary in Joseph M. Farley Unit No. 2 incorporates provisions for access for inservice inspection in accordance with Section XI of the ASME Code. Methods have been developed to facilitate the remote inspection of those areas of the reactor vessel not readily accessible to inspection personnel.

Section 50.55a(g), 10 CFR Part 50, defines the detailed requirements for the preservice and inservice inspection programs for light water cooled nuclear power facility components. Based upon a construction permit date of August 16, 1972, this section of the Code of Federal Regulations requires that a preservice inspection program be developed and implemented using at least the Edition and Addenda of Section XI of the ASME Code in effect 6 months prior to the date of the issuance of the construction permit. Also, the initial inservice inspection program must comply with the requirements of the latest Edition and Addenda of Section XI of the ASME Code in effect 12 months prior to the date of issuance of the operating license, subject to the limitations and modifications listed in Section 50.55a(b) of 10 CFR Part 50.

Our evaluation of the applicant's preservice inspection program indicates that the program meets the requirements of 10 CFR Part 50, paragraph 50.55a(g) provided relief as requested by the applicant is granted to use alternative examination requirements. We have completed our review of applicant's relief requests (Appendix B of this supplement). Based on our review of the preservice inspection program for Joseph M. Farley, Unit No. 2, we have determined that certain preservice examination requirements are impractical and performing these examinations would result in hardships or unusual difficulties without a compensating increase in quality and safety giving due consideration to the burden [illegible] would be placed on the applicant if the specific code requirements were imposed. Pursuant to 10 CFR 50.55a(g)(2) and (g)(6)(i), the relief requested by the applicant from preservice inspection is granted.

The granting of this relief from the Code requirements is authorized by law and will not endanger life or property or the common defense or security and is otherwise in the public interest.

The inservice inspection program will be evaluated after the applicable ASME Code Edition and Addenda have been determined and before the initial inservice inspections are performed.

The conduct of periodic inspections and hydrostatic testing of pressure retaining components of the reactor coolant pressure boundary, in accordance with the requirements of Section XI of the ASME Boiler and Pressure Vessel Code and 10 CFR Part 50, will provide reasonable assurance that evidence of structural degradation or loss of leaktight integrity occurring during service will be detected in time to permit corrective action before the safety functions of a component are compromised. Compliance with the inservice inspections required by this Code and 10 CFR Part 50 constitutes an acceptable basis for satisfying the inspection requirements of General Design Criterion 32.

5.7.2 Inservice Inspection of Class 2 and 3 Components

General Design Criterion 36, "Inspection of Emergency Core Cooling System," Criterion 39, "Inspection of Containment Heat Removal System," Criterion 42, "Inspection of Containment Atmosphere Cleanup Systems," and Criterion 45, "Inspection of Cooling Water System," Appendix A of 10 CFR Part 50, requires, in part, that the subject systems be designed to permit appropriate periodic inspection of important component parts to assure system integrity and capability.

Section 50.55a(g) of 10 CFR Part 50 defines the detailed requirements for the preservice and inservice inspection programs for light water cooled nuclear power facility components. Based upon a construction permit date of August 16, 1972, this section of the Code of Federal Regulations requires that a preservice inspection program be developed for Class 2 components and be implemented using at least the Edition and Addenda of Section XI of the ASME Code in effect 6 months prior to the date of issuance of the construction permit. Also, the initial inservice inspection program must comply with the requirements of the latest Edition and Addenda of Section XI of the ASME Code in effect 12 months prior to the date of issuance of the operating license, subject to the limitations and modifications listed in Section 50.55a(b) of 10 CFR Part 50.

Our evaluation of the applicant's preservice inspection program indicates that the program meets the requirements of 10 CFR Part 50, paragraph 50.55a(g) provided relief as requested by the applicant is granted to use alternative examination requirements. We have completed our review of applicant's relief requests (Appendix B of this supplement). Based on our review of the preservice inspection program for Joseph M. Farley, Unit No. 2, we have determined that certain preservice examination requirements are impractical and performing these examinations would result in hardships or unusual difficulties without a compensating increase in quality and safety giving due consideration to the burden that would be placed on the applicant if the requirements were imposed. Pursuant to 10 CFR 50.55a(g)(2) and (g)(6)(i), the relief requested by the applicant from preservice inspection is granted.

The granting of this relief from the Code requirements is authorized by law and will not endanger life or property or the common defense or security and is otherwise in the public interest.

The inservice inspection program will be evaluated after the applicable Code Edition and Addenda have been determined and before the initial inservice inspections are performed. Compliance with the inservice inspections required by the ASME Code and 10 CFR Part 50 constitutes an acceptable basis for satisfying applicable requirements of General Design Criteria 36, 39, 42, and 45.

### 5.9 Integrity of the Steam Generator

#### 5.9.1 Steam Generator Materials

The materials used in Class 1 and Class 2 components of the steam generators were selected and fabricated according to codes, standards, and specifications acceptable to the staff. The steam generator pressure retaining parts are designed and manufactured to meet the ASME Code Section III.

The primary side of the steam generator is designed as ASME Code Class 1, as required by the staff. The secondary side pressure boundary parts of the steam generator are also designed, manufactured, and tested in accordance with the requirements of the ASME Code. The onsite cleaning and cleanliness controls during fabrication conform to the recommendations of Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants." Conformance with applicable codes, standards, and regulatory guides constitutes an acceptable basis for meeting, in part, the requirements of General Design Criteria 14, 15, and 31.

#### 5.9.2 Steam Generator Inservice Inspection

General Design Criterion 32, "Inspection of Reactor Coolant Pressure Boundary," Appendix A of 10 CFR Part 50, requires, in part, that components which are part of the reactor coolant pressure boundary or other components important to safety be designed to permit periodic inspection and testing of critical areas for structural and leaktight integrity.

The components in the steam generator are classified as ASME Boiler and Pressure Vessel Code Class 1 or 2, depending on their location in either the primary or secondary coolant systems, respectively. The Joseph M. Farley Unit No. 2 steam generators are designed to permit inservice inspection of the Class 1 and 2 components, including individual tubes.

The design aspects that provide access for inspection and the proposed inspection program for tubing should follow the recommendations of Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," Revision 1, NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors," Revision 2, and comply with the requirements of Section XI of the ASME Code with respect to the inspection methods to be used, provisions for a baseline inspection, selection and sampling of tubes, inspection intervals, and actions to be taken in the event defects are identified. In Amendment 73 to the Final Safety Analysis Report, the applicant has stated its intent to conform to Regulatory Guide 1.83, Revision 1, NUREG-0452 Revision 2, and Section XI of the ASME Code. The proposed Farley Unit 2 Technical Specification for inservice inspection of steam generator tubes is based on these documents and, therefore, is an acceptable program.

Conduction of an acceptable inservice inspection program for steam generator tubes constitutes an acceptable basis for meeting the applicable requirements of General Design Criterion 32, "Inspection of Reactor Coolant Pressure Boundary."

### 5.9.3 Secondary Water Chemistry

In late 1975, we incorporated provisions into the Standard Technical Specifications (STS) that required limiting conditions for operation and surveillance requirements for secondary water chemistry parameters. The technical specifications for all pressurized water reactor plants that have been issued an operating license since 1974, contain either these provisions, or a requirement to establish these provisions after baseline chemistry conditions have been determined. The intent of the provisions was to provide added assurance that the operators of newly licensed plants would properly monitor and control secondary water chemistry to limit corrosion of steam generator tubes and the tube support plates.

In some plants, technical specifications on secondary water chemistry have significantly restricted operational flexibility with little or no benefit with regard to limiting degradation of steam generator tubes. Based on this experience and the knowledge gained in recent years, we have concluded that technical specification limits are not the most effective way of assuring that steam generator tube degradation will be minimized.

Due to the complexity of the corrosion phenomena involved and the state-of-the-art as it exists today, we believe that, in lieu of specifying limiting conditions in the technical specifications, a more effective approach would be to institute a license condition that required the implementation of a secondary water chemistry monitoring and control program containing appropriate procedures and administrative controls.

The required program and procedures are to be developed by the applicant with input from their reactor vendor or other consultants, to more readily account for site and plant features that affect chemistry conditions in the steam generators. In our view, plant operation following such procedures would provide assurance that licensees would devote proper attention to controlling secondary water chemistry, while also providing the needed flexibility to allow them to deal more effectively with any off-normal conditions that might arise.

Consequently, we requested, in a letter dated August 2, 1979, that the applicant propose a secondary water chemistry program which will be referenced in a condition to the license. In the letter we concluded that such a license condition, in conjunction with existing Technical Specifications on steam generator tube leakage and inservice inspection, would provide the most practical and comprehensive means of assuring that steam generator tube integrity would be maintained.

In a letter dated September 17, 1979, the applicant provided a water chemistry monitoring and control program for the Farley Unit 2 Nuclear Plant which 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. Procedures 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 our evaluation of the Farley Unit 2 secondary water chemistry monitoring and control program, we stated the position that we would require the applicant to repair or plug a condenser leak within 96 hours of confirming the existence of a condenser leak in accordance with Branch Technical Position MTEB 5-3 appended to Standard Review Plan 5.4.2.1.

In a letter dated June 27, 1980, the applicant stated that the opinion that a requirement to find and repair condenser leaks which do not result in contaminant levels in the steam generators in excess of secondary system chemistry specifications within 96 hours is unrealistic. The basis for the applicant's opinion was that their secondary water chemistry control program incorporated steam generator blowdown cation conductivity operational limits with corrective action requirements in addition to an abnormal operating procedure which provided corrective action in the event of a condenser leak.

We discussed this issue with the applicant and stated the following remaining concerns:

1. The abnormal procedure should identify a specific continuously monitored condensate sample point for confirming a condenser leak and

2. The water chemistry program should be expanded to include operational limits based on the analysis of a feedwater sample rather than just the steam generator blowdown sample. This will provide earlier indication of impurities entering the steam generator before the entire steam generator secondary side reaches or exceeds the impurity operational limits.

Accordingly, the applicant has agreed to modify its water chemistry program as follows:

1. The condensate pump discharge sample point along with the existing continuous cation conductivity monitoring capability will be used as the control point for confirming a condenser leak and to implement the abnormal operating procedure.

2. Feedwater impurity-time operating limits will be added. The limits will utilize feedwater pH and cation conductivity impurity-time limit values the same as used for steam generator blowdown limits.

The applicant submitted confirmation of these changes by letters dated July 29, 1980 and August 5, 1980. We find this alternate approach to MTEB BTP 5-3 for condenser leak corrective action acceptable since it provides an ef integrated impurity-time limit to the quantity of impurities entering the steam genera.

We have reviewed the applicant's secondary water chemistry monitoring and control program and, based on the above evaluation, we have determined that it meets (1) the NRC staff requirement. delineated in the August 24, 1979 letter; (2) Positions 2, 3, and 4 in BTP MTEB 5-3; (3) the acceptance criteria of Standard Review Plan, Section 5.4.2.1 for secondary coolant purity; and (4) the requirements of General Design Criterion 14, "Reactor Coolant Pressure Boundary," as it relates to secondary water chemistry control and monitoring. Accordingly, we conclude that the applicant's secondary water chemistry monitoring and control program is acceptable. This program will be a condition of the license.

It should be noted that the steam generators of Farley Nuclear Plant Unit 2 are of the Westinghouse "51" series design having carbon steel supporting plates with drilled tube support 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.

In spite of the possibility of tube cracking, we have concluded that 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 have been 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. Inservice inspection requirements and preventative tube plugging criteria have been established to provide assurance that the great majority of degraded tubes will be identified and removed from service before leakage develops.

5.9.4 Steam Generator Inspection Ports

For some forms of steam generator degradation which have occurred in units similar to the J. M. Farley design, eddy current testing and tube gauging alone are not sufficient to assess and monitor tube and support plate conditions. In order to perform adequate assessment and monitoring of these areas, we require that inspection ports be installed in each steam generator. These ports should be installed just above the upper support plate and in line with the tube lane. At the upper support plate level, at least one inspection port is required which shall be large enough for visual observation of the tube lane.

Under the as low as reasonably achievable (ALARA) concept, NRC has been requesting that all possible steam generator modifications be made before the start of operations in order to

*Criteria in Appendix A to 10 CFR Part 50: Criterion 14, "Reactor Coolant Pressure Boundary"; Criterion 15, "Reactor Coolant System Design"; Criterion 31, "Fracture Prevention of Reactor Coolant Pressure Boundary."

minimize personnel exposure. Although installation prior to initial operation is preferable, we have determined that the potential installation exposure following the first cycle of operation is not significant enough to justify the delay of the initial startup of the plant to permit the installation of inspection ports. However, since secondary side contamination will increase as the operating time increases, we require that these ports be installed prior to startup after the first refueling.

By letter dated June 27, 1980, applicant has agreed to install an inspection port above the upper tube support plate in each steam generator. Installation of the ports has been started and will be completed prior to initial operation. The Office of Inspection and and Enforcement will verify completion prior to fuel landing.

5.9.5 Row One Steam Generator Tubes

Operating experience has shown that the Row 1 tubes in the steam generators of Westinghouse design are particularly susceptible to an early onset of cracking because of their small bend radius. We do not currently require licensees to plug Row 1 tubes prior to startup or issuance of full power license. Westinghouse has committed (letter from R. M. Anderson to R. H. Vollmer, May 12, 1980) to a program to determine the particular susceptibility of Row 1 tubes to cracking. The program involves removing numerous tubes from the Trojan plant and subjecting them to nondestructive and destructive testing to identify the cause of cracking and to develop a field inspection method capable of detecting potential leaking tubes. The results of this evaluation are expected to be available in October 1980. We shall review the program results and decide at that time on the necessity to plug the Row 1 tubes.

Although the possibility of tube and tube support plate degradation 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 requirements 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.

# 6.0 ENGINEERED SAFETY FEATURES

## 6.2 Containment Systems

### 6.2.2 Containment Heat Removal

One of the recommendations of the Three Mile Island, Unit 2 (TMI-2) Lessons Learned Task Force was to automate initiation of the auxiliary feedwater system (see Requirement II.E.1.2 of Section 22.2 of this supplement). Automating the auxiliary feedwater system could cause an increase in energy released to containment after a main steam line break, thereby increasing the calculated peak containment pressure for this accident, compared to the calculated peak containment pressure assuming auxiliary feedwater is stopped.

By letter dated October 13, 1979, the staff requested the applicant to assess the potential for containment overpressurization due to the continuous addition of auxiliary feedwater to the affected steam generator at pump run-out flow following a postulated main steam line break accident. By letter dated April 1, 1980, the applicant responded to the staff's letter. In the original accident analysis, consideration was given to auxiliary feedwater pump run-out. The applicant performed the analysis using a run-out flow condition of 800 gpm.

The staff concurs with the applicant's finding that for a main steam line break inside containment, the peak containment pressure will remain below the containment design pressure even with the addition of auxiliary feedwater at the pump run-out flow rate. We conclude that the containment meets the applicable requirements of General Design Criterion 50, "Containment Design Basis," and is therefore acceptable.

### 6.2.3 Containment Isolation System

Our review of the containment isolation system includes review of the containment purge system. This system will be used to reduce airborne radioactivity in the containment to permit personnel entry. Our requirements for the purge system are contained in Branch Technical Position CSB 6-4, "Containment Purging During Normal Operation" attached to Standard Review Plan Section 6.2.4, "Containment Isolation System."

The Farley containment purge system consists of two paths as described in the FSAR Section 6.2.3; a large flow path through 48-inch butterfly valves, and a small flowpath through 18-inch butterfly valves. Applicant is conducting an operability program for the 48-inch valves. We will require the applicant to keep these 48-inch valves in the closed position during plant operation by Technical Specifications until operability is demonstrated. The 18-inch valve operability program has been completed but not satisfactorily documented by the applicant. We will require the applicant to block the 18-inch valves at no more than 50 degrees open (full open is 90 degrees) by Technical Specifications. This will provide reasonable assurance that the valves will operate under accident conditions.

A description of the 18-inch purge valve operability program for Farley Unit 1 is given in applicant's letter dated December 10, 1979. A comparison of the Unit 1 purge system operation with Branch Technical Position CSB 6-4 is given in applicant's letter dated February 5, 1979. By letter dated June 30, 1980, applicant has stated that this information is also valid for Unit 2.

We are currently reviewing the Farley Plant purge system. In order to complete our review of the purge system, we required the following information by letter dated Auguat 25, 1980.

(1) A description of the containment purge system design that assures blockage of the purge valves by debris will not occur. The description should include quality and seismic classification of the blockage prevention measures.

(2) A description of the means for detecting high radioactivity conditions prior to opening the purge valves.

(3) A description of how the use of the purge system will be limited to a total of no more than 90 hours per year per reactor during normal plant operating modes.

(4) Information regarding the operability of the purge valves.

The resolution of these issues will provide increased assurance that the valves will operate under accident conditions and radioactive releases will be minimized. However, operation of the Farley Nuclear Plant is not contingent upon the resolution of these issues because there is reasonable assurance that the valves will perform their accident function from the 50-degree open position. The resolution of this matter will be reported in a future supplement to the Safety Evaluation Report, prior to full power operation.

### 6.2.5 Containment Leakage Testing Program

We have reviewed the applicant's containment leak testing program as presented in Section 6.2 of the Final Safety Analysis Report, as amended through Amendment 72, for compliance with the containment leakage testing requirements specified in Appendix J to 10 CFR Part 50, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." Compliance with Appendix J provides adequate assurance that containment integrity can be verified throughout the service lifetime and that leakage rates will be periodically checked during service on a timely basis to maintain leakage within the specified limits. Maintaining containment leakage within specified limits provides reasonable assurance that, in the event of a radioactivity release within the containment, the loss of containment atmosphere through leak paths will not be in excess of the limits specified for the site.

The applicant has provided a detailed discussion of the containment integrated leak rate (Type A) test procedure and acceptance criteria. All systems penetrating containment will be vented to the containment atmosphere so that the differential pressure expected during an accident will exist across the containment isolation valves for the Type A test.

The applicant has listed all the containment penetrations and has itemized all the local leak testing that will be performed. Schematic drawings of each piping system penetrating containment have been submitted showing the isolation valve arrangements. The location of test connections and vents for each isolation valve subject to local (Type C) leak testing is such that the test pressure will be applied in the same direction as the pressure existing when the valve performs its safety function.

With the exception of the secondary system penetrations, all containment penetrations will be subject to local Type B (electrical penetrations, personnel air locks, and flanged penetrations) or Type C leak tests.

If primary to secondary steam generator tube leakage is postulated to occur, containment atmosphere leakage could pass through the steam generator, and the secondary system isolation valves would become containment atmosphere leak paths. However, post-LOCA procedures call for covering the steam generator tube bundles with feedwater. By the time the steam generator depressurizes to the containment pressure, the head of feedwater will prevent leakage from occurring across the tube bundles. We concur with the applicant's finding that the secondary system containment isolation valves will not become potential containment leak paths and, therefore, local Type C leak tests should not be required for these valves.

Section III.D.2 of Appendix J to 10 CFR 50 requires airlocks to be leak tested at 6-month intervals and after each opening during the intervals. Section III.B.2 of Appendix J requires all penetrations to be leak tested at the calculated peak containment accident pressure, corresponding to the design basis accident.

Based on plant operating experience, requiring an airlock to be leak tested after each opening is impractical when frequent airlock usage is necessary over a short period of time. Furthermore, the Farley 2 airlock design incorporates dual seals on the airlock doors with the capability to pressurize the volume between the seals. Therefore, the applicant proposes to leak test the airlock door seals within 3 days after opening an airlock. This will permit door seal integrity to be demonstrated without pressurizing the entire airlock. This is an acceptable test method for tests other than the 6-month test. Testing of the door seals is more practical and still provides the desired confidence that the leak tightness of the airlock is within acceptable limits.

The airlock door seal tests will be performed at a pressure less than the calculated peak accident pressure. The acceptance criterion for the door seal tests is no detectable seal leakage when the volume between the seals is pressurized to 10 pounds per square inch for at least 15 minutes. The lower test pressure of 10 pounds per square inch is sufficient to verify that door seal integrity is being maintained and that the door seals are free of dirt and foreign objects. The test pressure is recommended by the air lock manufacturer, and testing at the lower pressure is expected to extend the seal life. We therefore conclude that the use of a test pressure of 10 pounds per square inch for the door tests is acceptable, although it is lower than the test pressure specified by Appendix J.

Pursuant to 10 CFR 50.12(a), an exemption is granted from the requirement in Section III.B.2 of Appendix J, 10 CFR 50, to leak test airlock door seals at calculated peak accident pressure after each opening. Granting of this exemption is authorized by law and will not endanger life or property or the common defense or security and is otherwise in the publc interest.

The applicant will retain the 6-month leak test of the airlocks at a test pressure equal to the calculated peak accident pressure, in accordance with Appendix J.

Additional staff effort on containment leak testing that will lead to a revision of Appendix J is being done in conjunction with the Office of Standards Development. The revised Appendix J will be applicable to all plants depending on their licensing status and design.

Closed systems outside containment (e.g., the emergency core cooling system and the containment spray system) will become extensions of the containment boundary following a loss of coolant accident. One of the requirements for full power operation (III.D.1.1) in NUREG-0694, "TMI-Related Requirements for New Operating Licenses," is that leakage from such systems shall be maintained as low as practical and leak tests shall be run periodically. We will report our evaluation of leak testing of these systems in a future supplement to our Safety Evaluation Report prior to full power operation.

## 6.3 Emergency Core Cooling System

### 6.3.3 Tests and Inspections

In Farley Unit 2 there are four intakes that take water from the containment floor following a loss-of-coolant accident and recirculate it to the safety injection system and the containment spray system. In Supplement 3 of our Safety Evaluation Report, it was concluded that tests of a full scale model of intake number one of the four intakes had led to intake design improvements. These improvements have subsequently been applied to models of intakes 2, 3, and 4 with resultant demonstration of vortex suppression with up to 50 percent intake screen blockage. Pressure loss coefficients were developed for each of the four intakes. Results are reported in Appendix 6C to the Final Safety Analysis Report, as amended through Amendment 72.

Preoperational tests were performed on the plant safety injection system and containment spray system while drawing water from the refueling water storage tank. Loss coefficients for major sections of pump inlet and pump discharge lines were developed from these tests. When considered in combination with the intake loss coefficients, it was determined that pump runout flow will be higher than the available net positive suction head (NPSH) would allow without cavitation. Flow restriction orifices were sized and installed to limit the runout flow and thus the NPSH required for each pump. This provides a margin in excess of 2 feet for each low pressure safety injection pump. The tests and results are discussed in the FSAR as amended through Amendment No. 72.

The model test program demonstrated that without vortex suppression equipment in place, severe vortex conditions occurred. The Farley-2 Technical Specifications will include a condition to assure that the plant will not be operated without the intake trash racks, screens, and inner cages being properly installed and exhibiting no evidence of structural distress or corrosion.

The staff is conducting a generic program (A-43, "Containment Sump Performance") that addresses emergency core cooling system hydraulic performance during recirculation as affected by potential break locations and debris from insulation or other sources. Additional studies are needed on the use of insulation inside containment and the response of insulation and other materials to loss-of-coolant accident conditions. Until such time as resolution is achieved, four near-term actions are being required: (1) reevaluate the NPSH available to each safety system pump and verify a margin of 1 foot or more over the required NPSH at limiting runout conditions; (2) establish a housekeeping program to assure that the plant is always restored to "as-licensed" cleanliness prior to power operations; (3) reevaluate the insulation used inside containment to assure that insulation debris would not be expected to block approach paths, trash racks, or screens in such a manner as to jeopardize intake performance and that debris penetrating the intake screens would not be expected to compromise safety system life or performance or degrade core cooling; and (4) describe the available instruments and controls, and provide procedures permitting the operator to detect problem conditions and to take corrective actions to maintain adequate core cooling even if air entrainment, cavitation, or debris entrainment were to occur.

As Farley Unit 2 has successfully completed tests demonstrating operability with up to 50 percent blockage of the intakes, Action 1 has been acceptably completed. Action 2 will be accomplished by including a technical specification requiring it. Action 4 is required to be accomplished before full power operation. Our evaluation of Action 4 will be reported in Supplement No. 5 to the SER. Action 3 is required to be accomplished before startup after the first refueling.

## 7.0 INSTRUMENTATION AND CONTROLS

### 7.3 Engineered Safety Features Actuation and Control

On November 7, 1979, Virginia Electric and Power Company reported that following initiation of safety injection at North Anna Unit 1, the use of reset pushbuttons alone resulted in certain ventilation dampers changing position from their emergency mode (closed) to their normal mode (open). On March 13, 1980 the Commission issued IE Bulletin No. 80-06 "Engineered Safety Features (ESF) Reset Controls" to all licensees with operating PWR and BWR facilities (including Alabama Power Company) requiring:

(1) a design review to determine whether or not upon reset of an engineered safety feature actuation signal, all associated safety-related equipment remains in its emergency mode;

(2) a schedule for the performance of tests to verify that equipment remains in its emergency mode when actuation signal is removed or manually reset; and

(3) a description of corrective actions if equipment is found to not remain in the emergency mode following reset of its actuation signal.

Alabama Power Company has responded to IE Bulletin 80-06 by its letter dated June 13, 1980, for both Farley Units 1 and 2. We are currently reviewing applicant's information and will report our evaluation in an SER supplement prior to full power operation. Plant operation during completion of this confirmatory review is acceptable because the applicant has reviewed the potential problem and stated that he will perform confirmatory testing prior to fuel loading. The Office of Inspection and Enforcement will verify completion of the tests prior to fuel loading.

### 7.7 Environmental and Seismic Qualifications

#### 7.7.1 Environmental Qualification of Pressure Transmitters

The corresponding section in Supplement No. 3 to the Farley Safety Evaluation Report identified four groups of process instrumentation transmitters which were required to be replaced with environmentally requalified transmitters. These four groups were (a) pressurizer level transmitters, (b) reactor coolant system wide range pressure transmitters, (c) steam generator level narrow range transmitters, and (d) steam generator level wide range transmitters. These transmitters were Westinghouse supplied Barton Lot 1 instrument transmitters which were identified by the staff as not fully meeting the post-accident long-term-monitoring environmental qualification requirements. Requalified transmitters for the above applications were required to be installed in Unit No. 2 of the Farley Station prior to its initial fuel loading.

In order to comply with these post-accident long-term-monitoring environmental qualification requirements, the Farley Unit 2 design will employ the Barton Lot 2 process instrument transmitters for the four functions identified above. The essential difference between the Lot 2 and Lot 1 instrument transmitters is that the Lot 2 instruments use a circuit board and associated amplifier which differs slightly from that used for the Lot 1 instruments. By letters dated December 21, 1979 and May 21, 1980, Westinghouse provided discussion and results of the environmental qualification tests which were performed on seven of the Lot 2 instrument transmitters. For these tests, the Westinghouse acceptance criterion was essentially that these instruments perform their function within defined allowable accuracies when subjected to environmental conditions. Except for one test transmitter, test results demonstrated that the Westinghouse acceptance criteria were satisfied when the test units were subjected to a single set of environmental conditions which envelop the loss-of-coolant accident and the steam line break. For one test transmitter, the negative error was larger than that allowed by the Westinghouse criteria. Westinghouse concluded that these large negative errors were predictable and were dependent upon the resistance value of the resistor used in the temperature compensation network of the transmitter. The transmitters used in Farley Unit 2 were reviewed by the applicant. The applicant found that none of the transmitters used in the Farley 2 plant have an unacceptably large negative error.

We conclude that the Barton Lot 2 transmitters used in Farley 2 have been acceptably qualified for accident environment and meet the applicable requirements of General Design Criterion 4, "Environmental and Missile Design Basis."

### 7.7.2 Environmental Qualification of Safety-Related Electrical Equipment

The staff has recently published guidance to be used in environmentally qualifying electrical equipment (NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," dated December 1979). By letter dated February 21, 1980, we requested the applicant to review their environmental qualification documentation and provide us with the results of this review for all safety-related electrical equipment installed at this unit with the purpose of establishing that the qualification methods used and results obtained are in conformance with the staff positions contained in NUREG-0588.

The Commissioner's Memorandum and Order dated May 23, 1980, directs the staff to complete its review of environmental qualification including the publication of the Safety Evaluation Reports by February 1 1981, for all operating reactors. Also, this order directs that by no later than June 30, 1982, all electrical equipment in operating reactors subject to this review be in compliance with NUREG-0588 or Guidelines for Evaluating Environmental Qualification of Class IE Electrical Equipment in Operating Reactors. Accordingly, the staff intends to complete the environmental qualification review of Farley 2 in accordance with these stated dates.

The applicant will provide by September 15, 1980, the results of the review of all safety-related equipment that could be exposed to a harsh environment. Any apparent deficiencies in documentation will be corrected by providing confirmatory test data or justification on a schedule compatible with completion of the staff's review by February 1, 1981, as required by the Commission's order.

We conclude that operation is acceptable while the staff's review is conducted because environmental qualifications to criteria that predate NUREG-0588 have been found adequate. We will report our evaluation of applicant's review in a future supplement prior to full power operation.

### 7.9 Loss of Non-Class IE Instrumentation and Control Power System Bus During Operation

On November 30, 1979, the Office of Inspection and Enforcement issued IE Bulletin 79-27, "Loss of Non-Class IE 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 volt alternating current control power to these plant systems. Further, IE Information Notice 80-10, issued on March 6, 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.

By letter dated July 17, 1980, applicant has provided its response to IE Bulletin 79-27 for Unit 2. The response indicated that no deficiencies were identified as a result of applicant's review of Farley Unit 2 in accordance with the action items in the Bulletin. The staff will complete its review and resolution of this matter before authorizing operation above five percent power. Plant operation is acceptable pending completion of our confirmatory review because the applicant has found no deficiencies.

### 7.10 Temperature Effects on Level Measurement

On August 13, 1979, the Office of Inspection and Enforcement issued IE Bulletin 79-21, "Temperature Effects on Level Measurements," to all utilities operating pressurized water reactors including Alabama Power Company. This bulletin required licensees to consider the effect of containment temperature under accident conditions on the reference leg water column of steam generator level instruments and the resultant error in indicated water level.

Applicant has reviewed its steam generator level instruments in accordance with IE Bulletin 79-21 requirements and reported the results of its review for Units 1 and 2 in a letter dated November 1, 1979. The applicant has stated that the steam generator narrow range reference legs have been insulated to minimize the error due to short-term reference leg heatup during a high energer line break inside the containment. In addition, the applicant has included an allowance for residual temperature effects in the steam generators level trip setpoints and has agreed to modify emergency operating procedures to assure that the operator will account for temperature effects on reference legs for both steam generator and pressurizer level instrumentation during the post-accident monitoring period.

As a part of our review of the Farley level instrumentation, we assessed the method used for establishing the low-low steam generator level trip setpoint. This setpoint is adjusted above zero-measured level by an amount which just equals the accumulation of all system errors, including temperature effects on the reference legs. We find this method to be unacceptable for establishing the setpoint for a safety action because these level transmitters do not respond to a reduction of water level in the steam generators below the level corresponding to the zero-measured level. Therefore, we requested the applicant to increase the trip setpoint above that required by their present sum of system errors in order to provide an additional margin of safety for this safety action.

We conclude that the applicant has resolved the concerns raised by Westinghouse as described in IE Bulletin 79-21. We require that steam generator low-low level setpoints included in the Farley 2 Technical Specifications reflect additional margin of safety to give added assurance that there will be no loss of safety action. We further conclude that the applicant's level instrumentation complies with the applicable requirements of General Design Criterion 13, "Instrumentation and Control," and General Design Criterion 20, "Protection System Functions," and therefore is acceptable.

## 8.0 ELECTRIC POWER

### 8.2 Offsite Power System

The criteria and staff positions pertaining to degraded grid voltage protection and adequacy of station electric distribution systems voltages were transmitted to the applicant by our letter dated November 27, 1978.

By letters of January 15, 1979, October 10, 1979, and July 17, 1980, the applicant proposed certain design modifications and associated changes to the technical specifications. Our evaluation of these submittals follows and is based on: (1) General Design Criterion 17, "Electrical Power System," (2) IEEE Std. 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Station," and (3) IEEE Std. 308-1974, "Class 1E Power Systems for Nuclear Power Generating Stations."

As part of its response to our positions, the applicant made certain design modifications and proposed changes to the technical specifications for the Farley Nuclear Plant, Units 1 and 2. These changes are as follows:

a. The installation of second level undervoltage protection with a higher undervoltage setpoint and a time delay to detect sustained degradation of voltage.

b. Technical specifications that require calibration and testing of the second level undervoltage protection systems and equipment.

c. Technical specifications setting the second level undervoltage relay trip setpoint at a value of 88 ± 1 percent of the rated voltage, 4160 volts, with a time delay of 20 to 30 seconds, configured in a two-out-of-three coincidence logic.

We have reviewed the information provided on the proposed changes and conclude that they are acceptable because they meet our positions, as described below.

Position 1 - Second Level Undervoltage or Overvoltage Protection With a Time Delay

The Farley plant is furnished with loss of voltage protection using a set of undervoltage relays connected to the buses 1F and 1G (2F and 2G for Unit 2). These relays sense the undervoltage (loss of voltage) at 77.45 percent of the nominal bus voltage. In addition to the loss of voltage protection provided for Farley plant, the licensee has installed a second level of undervoltage protection consisting of one set of three additional voltage relays on Unit 1 (and 3 for Unit 2) safeguard buses 1F and 1G (2F and 2G for Unit 2). The undervoltage relays are configured in a two-out-of-three coincidence logic to preclude spurious trips of the offsite power source. The relays are connected in such a manner that when any two or three of the relays are actuated, the associated breakers supplying offsite power will be tripped. The new undervoltage protection system meets the requirements of IEEE-279-1971 and is acceptable.

The technical specifications will include limiting conditions for operation and surveillance requirements, as well as trip setpoints for allowable values for the second level of voltage protection. We find this aspect of the design to be acceptable.

The undervoltage setpoint and allowable time duration of a degraded voltage must not result in failure of safety systems or components. In order to demonstrate for a degraded voltage condition that the time delay chosen does not exceed the maximum time delay assumed in the accident analyses, the applicant addressed two accident sequences to demonstrate the adequacy of the design. The first sequence postulated an accident with a degraded grid voltage condition where the 4160 volt safeguards bus voltage is degraded but is still of a sufficient magnitude to allow the safeguard motors to start and accelerate, and the second sequence postulated an accident with a degraded grid voltage condition where the 4160 volt safeguards bus voltage is degraded to a level where the safeguards motors cannot start and accelerate. It should be noted that for the second sequence the first level of undervoltage protection relays (loss of voltage relays) will be initiated rather than the second level of undervoltage protection relays due to the inverse characteristics of these relays. For the sequences presented above, it has been demonstrated that the time delay chosen for the second level of undervoltage relays is less than the maximum time delay assumed in the FSAR accident analysis. We find this to be acceptable.

For these safeguard buses, the acceptable minimum (degraded sustained voltage has been established as 87 percent of the nominal bus voltage (4160 volts). The second level of undervoltage relays will have a trip setting of 88.34 percent of the nominal bus voltage with a time delay of 20 to 30 seconds.

Position 2 - Interaction of Onsite Power Sources With the Load Shed Feature

The proposed design of the load shedding action of all 4-kilovolt emergency buses 1F, 1H, 1G, 1J (2F, 2H, 2G, 2J for Unit 2) is initiated by the bus undervoltage relays, and it automatically load strips the bus prior to transferring from the offsite power system to an onsite diesel generator. The load shedding feature on these buses is not disabled while these buses are supplied power from the diesel generators.

The licensee has provided the following justification for retaining the load shedding feature on these buses. The load shedding feature of the train A buses is required to be maintained in an operable status even after the train A diesel generators are connected to those buses, in order to permit proper operation of the train A diesel generators, which may require realigning the train A diesel generators. This is due to the swing feature of the A diesel generators. On train B the present design provides for diesel generator 2C to be backed up by diesel generators 1B and 2B in the event of failure of diesel generator 2C. The load shed feature of buses 1J and 2J on bus undervoltage is necessary in conjunction with this back up feature to avoid the possibility of tying diesel generator 1B or 2B to a load bus.

The above discussion demonstrates the necessity of retaining the load shedding feature on 6 out of 8 of the safety buses only. For the remaining buses (as well as the others), the licensee has demonstrated that at no time during the loading sequence would the voltage decrease to a level which will actuate the load shedding feature, with considerable margin. Based on our review of the information provided by the applicant, we find this alternative design to be acceptable.

Position 3 - Onsite Power Testing

The technical specifications for Farley Un'.s 1 and 2 will satisfy our requirements with respect to our positions 3a, 3b, ?., and 3d. In regard to Position 3e, the licensee has stated that interruption of the diesel generators to test load shedding and load sequencing is not necessary, as this logic is tested during testing of Position 3a, 3b, 3c, and 3d and the load shedding feature is retained on the safety buses once the onsite sources are supplying power to the safety buses. We find this to be acceptable.

Position 4 - Optimization of Voltage Levels of the Safety-Related Buses

The licensee has demonstrated by analysis that the transformer tap settings have been fully optimized for Farley Units 1 and 2. A test was performed at Farley Unit 1 to verify that the analytical method used for calculating the voltage at all distribution levels are valid. This test case was modeled on the voltage drop computer program; however, the test was performed only on 4.16-kilovolt bus 1B (non-safety bus). The calculated voltages at the instant of motor starting was within 0.3 percent of the me[illegible]ous voltage for this condition. This test result validated the analytical values of voltages for bus '1B' only. The calculated voltages at the safety buses were not correlated with the measured values as required by our position. We informed the licensee that this was unacceptable and that we required the calculated voltages at the safety-related buses (for both Units) be verified by actual in-plant measurement to satisfy the requirements of this position.

Subsequently by letter of July 17, 1980, applicant committed to perform, prior to fuel loading, a test on Unit 2 which would consist of measuring the electrical parameters (voltage, current and power factor) under steady state load conditions on the 4160 volt (bus 2G), 600 volt (buses 2E and 2T), and 208 volt (bus 2T) safety buses which were determined by analysis to exhibit the largest voltage drops during the worst case analysis. These buses will be loaded with safety loads and the auxiliary bus upstream of these buses will be loaded with one 7000 horsepower circulating water pump. The resulting total load on the startup transformer will be approximately 38 percent of the full power load. The measured current and power factor will then be used as the input in the computer program model of the distribution system used for the worst case analysis. The computer results would then be compared with the measured test parameters to demonstrate the validity of the model and the calculated values.

Based on our evaluation, we conclude that the design modifications for Unit 2 are acceptable. The design modifications have been implemented by the applicant in accordance with the requirements of IEEE Standard 279-1971, IEEE Standard 308 and 10 CFR Part 50, Appendix A, General Design Criterion 17. The proposed modifications will protect the class 1E equipment and systems from a sustained degraded voltage of the offsite power source. The proposed changes to the technical specifications meet the criteria for testing of protection systems and equipment. Staff positions 1, 2 and 3 have been met by the applicant. Staff position 4, the applicant's proposed method for correlating the measured values with the analysis results is acceptable. The implementation of this commitment and the adequacy of the results obtained will be verified by the Office of Inspection and Enforcement prior to fuel loading.

## 8.3 Onsite Power System

### 8.3.1 A-C Power System

By letter of June 20, 1978, applicant reported that design conditions existed which could render swing Diesel Generators 1C and 1-2A inoperable when both Farley units are in operation and loss-of-offsite power (LOSP) on both units or LOSP on both units and loss-of-coolant accident (LOCA) on one unit occur. By letter of August 15, 1978, the licensee reported that after the two units go into operation, only one emergency source would be dedicated to the river water system pumps. The failure of this emergency source could leave both the units with no river water pumps available (required for safe shutdown). Subsequently, by letter of November 17, 1978 the licensee proposed design changes to eliminate these design deficiencies. Our evaluation of these design changes is provided below.

Loss of Offsite Power and Loss-of-Coolant Accident

One unacceptable design condition existed which could render swing Diesel Generators 1C and 1-2A inoperable when both Farley units are in operation and LOSP on both units or LOSP on both units and LOCA on one unit occur. This condition is the result of the manual alignment of the power supply to the motor control centers (MCC) which feed the auxiliaries of the subject diesel generators. Under this postulated condition, Diesel Generator 1C is a source of power for Unit 2 Train A hot shutdown loads and Diesel Generator 1-2A is a source of power for Unit 1 LOCA loads. If, at the time of the accident occurrence, the MCC that feeds Diesel Generator 1C auxiliaries is aligned to Unit 1, it will be deenergized and Diesel Generator 1C will lose its auxiliaries. At this time the MCC has to be connected to Unit 2 manually. If this manual action is not accomplished within the specified time Diesel Generator 1C becomes disabled. If Diesel Generator 1C is disabled, no source of power for Unit 2 Train A hot shutdown loads will be available. Thus a single failure on Unit 2 Train B can render Unit 2 incapable of being shutdown. Similarly if the MCC that feeds Diesel Generator 1-2 auxiliaries is aligned to Unit 2, at the time of the accident, it will be deenergized and Diesel Generator 1-2A loses its auxiliaries. If Diesel Generator 1-2A is disabled, no source of power for Unit 1 Train A LOCA loads will be available. In this case if we apply the single failure criterion to Unit 1 Train B, Unit 2 will meet the shutdown requirements, while Unit 1 cannot meet the LOCA requirements.

The licensee has taken the following corrective actions to correct this deficiency:

1. Replacement of the manual alignment of the MCC's that feed Diesel Generators 1C and 1-2A auxiliaries by automatic realignment.

2. A design change to automatically connect the MCC that feeds Diesel Generator 1C auxiliaries to (1) Unit 1 when Diesel Generator 1C is aligned to Unit 1, and (2) Unit 2 when Diesel Generator 1C is aligned to Unit 2.

3. A design change to automatically connect the MCC that feeds Diesel Generator 1-2A auxiliaries to (1) Unit 1 when Diesel Generator 1-2A is aligned to Unit 1, and (2) Unit 2 when Diesel Generator 1-2A is aligned to Unit 2.

Based on our review of the above modifications, we have concluded that the modifications to the onsite power system for Farley Units 1 and 2 will enable the subject diesel generators to meet the single failure criterion and thereby perform their safety function under the above postulated conditions. We further conclude that this design meets the applicable requirements of General Design Criterion 17, "Electric Power Systems," and is therefore acceptable. The Office of Inspection and Enforcement will verify that these modifications have been made prior to fuel loading.

Loss of Offsite Power and Loss of Pond Dam

A second problem identified concerning the diesel generators related to the following. One of the design bases for the Farley Nuclear Plant was to accommodate the loss of the cooling water pond dam along with loss of offsite power (LOSP) and a single failure. For this event, with only Unit 1 in operation, two diesel generators (1C-Train 1A and 2C-Train 1B) are dedicated to the river water system. Four river water pumps with automatic starting capability are available so that in the event of a single failure at least two river water pumps will start, meeting the minimum requirements for safe shutdown of the unit. Therefore, there is no deficiency for Unit 1 operation. For Units 1 and 2 operation, a minimum of four river water pumps are required for safe shutdown and to satisfy the single failure criterion, eight river water pumps are required. However, after two units go into operation, only Diesel Generator 2C-Trains 1B and 2B will be dedicated to the River Water System, leaving only four river water pumps available. The failure of Diesel Generator 2C could leave the entire plant with no river water pumps available.

In order to correct this deficiency, the licensee has taken the following corrective actions.

1. A design change to block containment cooler 2B from being added automatically on bus 2F. After LOSP loads are added to bus 2F, the sequencer on bus 2H will be unblocked to enable one river water pump to automatically be applied to bus 2H.

2. A design change to feed bus 1H from bus 1F after the LOSP sequencer has added the LOSP loads to bus 1F. Three Unit 1 train A river water pumps will then be started on bus 1H in sequence.

3. Should Diesel Generator 2C fail, Diesel Generator 1B will furnish power to Bus 1J and Diesel Generator 2B will furnish power to Bus 2J after the LOSP loads are applied on Buses 1G and 2G. Two river water pumps will start on Bus 1J and two river water pumps will start on Bus 2J.

We have reviewed the information provided by the applicant and conclude that the design modification of the onsite power systems for Farley Units 1 and 2 will ensure that the plant has adequate river water supply with both units operating in the event of the loss of the cooling water pond dam, loss of offsite power and a single failure. We further conclude that this design meets the applicable requirements of General Design Criterion 17, "Electric Power Systems," and is therefore acceptable. The Office of Inspection and Enforcement will verify that these design changes have been implemented prior to fuel loading.

# 9.0 AUXILIARY SY''EMS

## 9.2 Fuel Storage and Handling

### 9.2.2 Spent Fuel Storage

The Safety Evaluation Report, dated May 2, 1975, evaluated the storage of fuel assemblies in the Unit 1 spent fuel pool and the Unit 2 spent fuel pool based on a spacing of 21 inches between the center lines of adjacent assemblies. In FSAR Amendment 55, the applicant changed the design bases for the Unit 1 spent fuel pool to a spacing of 13 inches. In Amendment No. 8 to License No. NPF-2, the staff approved the increased storage capacity for Unit 1. In FSAR Amendments 70 and 72, the applicant changed the design bases for the Unit 2 spent fuel pool to a spacing of 13 inches.

The design and design bases for the modifications to the Unit 2 spent fuel pool are the same as those for the Unit 1 spent fuel pool. We conclude that the Unit 2 design modifications are the same as those approved for Unit 1, meet the requirements of General Design Criterion 62, "Prevention of Criticality in Fuel Storage and Handling," and are therefore acceptable.

## 9.3 Cooling Water Systems

### 9.3.1 Auxiliary Feedwater System

By letter dated January 10, 1978, the applicant reported a design deficiency in accordance with 10 CFR 50.55(e). The design deficiency was that a single failure of a Class 1E direct current emergency power bus would result in loss of one of the two motor-driven auxiliary feedwater pumps and also would result in loss of speed control for the turbine-driven auxiliary feedwater pump. Farley plant design bases (FSAR Section 6.5) require that two of the three auxiliary feedwater pumps must start and deliver feedwater to steam generators in the event of a steam or feedwater line rupture.

By letter dated December 20, 1978, the applicant stated that a separate 3-kilovolt ampere uninterruptible power system would be added to the auxiliary feedwater system to supply power for controls of the steam-driven auxiliary feedwater pump.

We have reviewed the design modifications and conclude that with the corrective action, a single failure would not prevent two of three pumps from starting and operating in the event of a steam or feedwater line break. We further conclude that the modified design of the power supply for the auxiliary feedwater system meets the requirements of General Design Criterion 44, "Cooling Water," and is therefore acceptable. The Office of Inspection and Enforcement will verify that these modifications have been made prior to fuel loading.

## 9.5 Fire Protection System

In Supplement No. 3 to our Safety Evaluation Report, we stated that our evaluation of the Farley Nuclear Plant fire protection program and any required modifications to the program would be provided in a future report. Our Fire Protection Safety Evaluation Report for Farley Units 1 and 2 was completed and transmitted by a letter to the applicant dated April 13, 1979.

The summary of our review and conclusions is reproduced below:

> "The fire protection for Farley 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 on May 2, 1975.
>
> "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, APC* conducted a re-evaluation of its proposed fire protection system for Farley Unit Nos. 1 and 2. APC submitted on September 15, 1977, a Fire Protection Program Reevaluation including a Fire Hazards Analysis. Subsequently in response to our additional positions, APC submitted four amendments to the program. APC has compared the program, in detail, with the guidelines of Appendix A to BTP ASB 9.5-1, "Guidelines for Fire Protection for Nuclear Plants."
>
> "During the course of our review we have reviewed APC's submittals and responses to our requests for additional information. In addition, we have made two site visits to evaluate the fire hazards that might exist in the Farley Plant and the existing and proposed design features and fire protection systems provided to minimize these hazards.
>
> "APC has either made modifications to improve or will improve the fire resistance capability for fire doors, dampers, fire barriers, and barrier penetration seals.
>
> "APC has also proposed to install additional sprinkler systems for areas such as the cable spreading room, component cooling pump area, and various other areas. 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, APC has committed to establishing emergency shutdown procedures to bring the plants to safe cold shutdown condition in the event of a damaging fire in either the cable spreading room or the main control room.
>
> "APC agreed to complete all required improvements for Unit Nos. 1 and 2 in a timely manner. We have reviewed the proposed schedule and priorities and find them acceptable. We have included Tables 1, 2, and 3 in this report to show implementation dates, priorities of Unit No. 1 work, and a summary of the proposed modifications for each fire area.**
>
> "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 System Technical Specifications provide adequate protection against fire that would threaten safe shutdown.
>
> "Our overall conclusion is that a fire occurring in any area of the Farley Nuclear Plant will not prevent either unit from being brought to a controlled safe cold shutdown. Further, such a fire would not cause the release of significant amounts of radiation.

* APC is an acronym for Alabama Power Company used in the Fire Protection SER.
**All modifications listed in these tables will be completed for Unit 2 prior to fuel load, except those noted in the text of this supplement.

"In summary, the Fire Protection Program for the Farley Nuclear Plant with the improvements already made, is adequate for the present time and, with the scheduled modifications, will meet the guidelines contained in Appendix A to BTP ASB 9.5-1. The Fire Protection Program as currently designed and installed meets General Design Criterion 3 and is acceptable."

By letter dated August 18, 1980, the applicant has stated that all modifications will be completed prior to fuel loading except for the following:

1. Smoke detection systems in the auxiliary building.

2. Hose stations in the Unit 2 cable tunnels between the diesel generator building and the auxiliary building.

Both of these modifications will be completed by October 30, 1980, or prior to initial criticality whichever is earlier.

We conclude that fuel loading is acceptable because all fire protection equipment required by the approved plan inside containment will be installed before fuel loading. We will condition the licensee to require all fire protection equipment to be installed and operable prior to November 1, 1980 in accord with the Commission's May 23, 1980 Memorandum and Order. We will include Fire Protection System Technical Specifications in the operating license for Unit 2 that are the same as those reviewed and approved for Unit 1. The Office of Inspection and Enforcement will verify completion of all modifications at the times stated above.

## 11.0 RADIOACTIVE WASTE MANAGEMENT

Our evaluation of the radioactive waste management system designed to process liquid, gaseous, and solid radwastes is discussed in detail in the Safety Evaluation Report (SER) for the Farley Nuclear Plant, dated May 1975.

In Supplement No. 3 to the SER, we provided liquid and gaseous source terms using the models and methodology described in NUREG-0017, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWR-GALE Code)," April 1976, and determined that liquid and gaseous waste treatment systems are in conformance with Appendix I to 10 CFR Part 50.

Subsequent to the issuance of Supplement No. 3, some changes have been submitted by the applicant in Amendments 67 through 72 to the Final Safety Analysis Report. There have not been any significant changes which would affect the conclusions of previous evaluations of the liquid and gaseous radioactive waste treatment systems. However, the applicant has proposed to delete the waste drumming station at Farley Plant, Unit No. 2, and process the waste from both units by the drumming station at Unit No. 1. This change is evaluated below.

### 11.4 Solid Waste Management System

The applicant estimates that each year the operation of Unit No. 2 will generate 11,500 cubic feet of wet solid waste consisting of primary spent resins, evaporator bottoms, and secondary spent resins containing 145 curies total; 10,000 cubic feet of dry solid waste consisting of paper, clothing, rags, towels, etc., containing 35 curies total; and 3,000 cubic feet of chemical drain tank effluents, containing 0.4 curie total.

Based on the information reported by licensees of other operating pressurized water reactors, we estimate that each year the operation of Unit No. 2 will generate 9,200 cubic feet of wet solid waste consisting of primary spent resins, evaporator bottoms, and secondary spent resins, containing 1600 curies and 4,100 cubic feet of dry solid waste consisting of paper, rags, clothing, towels, etc., containing less than 5 curies total. In addition, we have considered the applicant's annual estimate of 3,000 cubic feet of chemical drain tank effluents, containing less than 1 curie.

All the solid waste generated by both units will be processed by the radioactive waste drumming station for Unit No. 1. We have reviewed the information provided by the applicant and determined that, on the average, the drumming station will process 2.5 drums per hour during its operation. Considering the waste generated by both units, it is estimated that the processing of solid waste would require about 2450 system operating hours per year or a usage factor of 28 percent. This usage factor is reasonable to allow system maintenance and to accommodate any surges in waste production during operation of both units. Storage facilities to accommodate approximately 570 drums will be provided within the auxiliary building for each unit.

The technical specifications for the operation of Farley Nuclear Plant, Unit No. 2, require a process control program for the solidification and packaging of wastes by the radioactive solid waste system. The process control program currently in use for Farley Unit 1 is approved for interim operation for Unit 2 as well, pending final approval based on the information to be submitted by the applicant in an October 1, 1980 submittal. During this period of interim authorization, the applicant commits to shipping no waste that does not meet applicable conditions incorporated into the license of the burial ground to which the waste is shipped. Applicant has agreed to provide for review and approval by October 1, 1980, the bases and justification for the process control program to assure that shipped solid wastes will conform to applicable burial ground requirements. We will condition the license to require the submittal of this information. Based on the storage capacity for solid radwaste at Farley, the staff believes that approval of the final process control program can be delayed without affecting low power testing and does not involve a safety question.

Subject to approval of the process control program, we conclude that the processing and storage facilities for solid radioactive waste materials are adequate for operation of both units, including anticipated operational occurrences, meet the applicable requirements of General Design Criterion 60, "Control of Releases of Radioactive Materials to the Environment," and therefore are acceptable.

## 12.0 RADIATION PROTECTION

### 12.1 Radiation Protection Design Features

#### 12.1.1 Shielding

By letter dated February 20, 1980, we requested applicant to review potential high radiation levels in the vicinity of the spent fuel transfer tube when it is being used. We requested that structural barriers be placed to prevent inadvertent access to high radiation areas and that shielding be placed where necessary to assure acceptable radiation levels for operation personnel.

By letters dated March 17, April 14, and June 3, 1980, the applicant has provided information on the types of structural barriers and permanent and temporary shielding that will be provided to assure acceptable radiation levels in adjacent occupied areas. In addition, a plan and elevation layout drawing of the areas through which the spent fuel transfer tube passes was also provided. A special radiation survey will be conducted on Unit 2 when the first irradiated fuel assembly is transferred through the spent fuel transfer tube to determine if any ot streaming problems need to be corrected.

We have evaluated this information and have concluded that the radiation protection measures incorporated in the Farley design will provide reasonable assurance that occupational radiation exposures will be as low as is reasonably achievable during spent fuel transfer tube operation consistent with the guidelines of Regulatory Guide 8.8, "Information Relevant to Ensuring that Occupational Exposures at Nuclear Power Plants will be As Low As is Reasonably Achievable" (Revision 3) and meet the requirements of 10 CFR Part 20, "Standards for Protection Against Radiation." Therefore, the spent fuel transfer tube design and operation are acceptable.

### 12.2 Health Physics Program

Section 12.3 of the FSAR described the applicant's health physics (HP) program. In amendment 67 and 73 the applicant has revised the HP program to meet the needs of a two unit plant during normal operations, accident conditions and during major outages that requires supplemental workers and extensive work in high radiation areas. The description includes the radiation protection organization, equipment, instrumentation, and facilities and the procedures for radiation protection. The plant health physics organization is evaluated in I.B.1.2 of Section 22.2 of this supplement.

The radiation protection facilities at Farley will include a radiation protection (low-level activity) laboratory and offices, counting room, gas analysis room, sample room, radiochemistry laboratory, decontamination areas, change room and whole body counting area. Access control to radiation area is such that personnel must pass through a health physics control point during entry and exit.

Equipment to be used for radiation protection purposes includes fixed radiation detection instrumentation, portable and semi-portable radiation survey instruments, personnel monitoring instruments, air samples, respiratory equipment, fixed and portable area and airborne radioactivity monitors, and protective clothing. The applicant has increased the number and types of equipment to meet the needs of a two unit plant during normal operations, accident conditions and during major outages. We conclude that the health physics equipment, instrumentation and facilities to be used by the applicant will be adequate to maintain occupational exposures as low as is reasonably achievable (ALARA) and, therefore are acceptable.

The applicant has described the station procedures which will be used to implement the radiation protection program. The procedures described are for: access control; radiation work permits; personnel, equipment and area decontamination; personnel monitoring; radiation surveys; radiation protection training; contamination control; methods of maintaining exposures as low as is reasonably achievable and reviews of the effectiveness of the health physics program. A health physics manual describing facility and procedures will be provided to each permanently assigned employee. To ensure that exposures are maintained ALARA the applicant will develop procedures prior to issuance of the low power testing license for the HP program using the guidance of Regulatory Guide 8.8 when practicable. We have reviewed the applicant's internal dosimetry commitments. By letter dated July 18, 1980, the applicant will implement a bioassay program prior to issuance of the low power testing license in accordance with Regulatory Guide 8.9. The applicant has provided an acceptable alternative to Regulatory Guide 8.14, "Personnel Neutron Dosimeters," (Rev. 1). The procedures as described are consistent with the guidance of Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," (Rev. 2) and Regulatory Guide 8.8. These radiation protection procedures will be required to be established, implemented, and maintained by the Farley 2 Technical Specifications.

Based on our evaluation, we conclude that the radiation protection program incorporated in the Farley Plant design will provide reasonable assurance that occupational doses will be maintained as low as reasonably achievable and within the limits of 10 CFR Part 20. These radiation protection measures are consistent with the guidelines of Regulatory Guide 8.8. Therefore, the radiation protection program is acceptable.

## 13.0 CONDUCT OF OPERATIONS

### 13.5 Physical Security Plan

The applicant's physical security plan was originally approved by the NRC staff on February 23, 1979. The approved security plan addresses the protection of both Units 1 and 2 against radiological sabotage as required by 10 CFR Part 73.55.

As a result of subsequent revisions, the approved plan consists of a document entitled "Joseph M. Farley Nuclear Plant Modified Amended Security Plan" dated August 30, 1979. These security documents are withheld from public disclosure in accordance with Section 2.790(d)(1) of 10 CFR Part 2. In conjunction with the Unit 2 application, the staff has again reviewed the physical security plan against the requirements of 10 CFR Part 73.55 and has determined that the plan is acceptable except as noted below.

By letter dated August 18, 1980, the applicant committed to implementing certain changes in his physical security program. Satisfactory implementation of those commitments is required prior to fuel loading of Unit 2. The Office of Inspection and Enforcement will verify implementation prior to fuel loading.

In addition, we require that the applicant fully comply with the requirement of 10 CFR Part 73.55 which states that: All keys, locks, combinations, and related equipment used to control access to protected or vital areas shall be controlled to reduce the probability of compromise. Whenever there is evidence that any such key, lock, combination, or related equipment may have been compromised, it shall be changed. Upon termination of employment of any employee, such keys, locks, combinations, and related equipment to which that employee had access shall be changed. This requirement will be made a condition in the license.

The identification of vital areas and measures used to control access to these areas, as described in the plan, may be subject to amendments in the future based on a confirmatory evaluation of Unit 2 to determine those areas where acts of sabotage might cause a release of radionuclides in sufficient quantities to result in dose rates equal to or exceeding 10 CFR Part 100 limits.

# 14.0 INITIAL TEST PROGRAM

The Safety Evaluation Report for Farley Units 1 and 2 through Supplement No. 3 concluded that the initial test program for the facility as described in the Final Safety Analysis Report (through Amendment 61) was acceptable. The applicant proposed other changes to the initial test program in Amendments 62 through 73. We have evaluated the changes and found that they are consistent with present guidance for initial test programs. Therefore, we conclude that these changes are acceptable.

By letters dated May 28, 1980 and July 7, 1980, applicant described its modified startup physics test program for Unit 2, in which some of the startup tests performed on Unit 1 will not be repeated on Unit 2. We have reviewed the modified startup physics test program for Unit 2. The basis for the elimination of some of the startup tests is that the design of Unit 2 is essentially identical to the design of Unit 1. The tests performed on Unit 1 were all satisfactory. To verify that the as-built core of Unit 2 is essentially identical to that of Unit 1, the test results for Unit 2 will be compared to those of Unit 1 with acceptance criteria that are tighter than those used for Unit 1. A similar modified startup physics test program was approved by NRC for North Anna Unit 2. We conclude that the modified startup physics test program for Unit 2 meets the applicable requirements of 10 CFR 50.34, "Contents of applications; technical information," and Appendix B to 10 CFR Part 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and is therefore acceptable.

# 15.0 ACCIDENT ANALYSIS

## 15.2 Thermal and Hydraulic Analyses

### 15.2.2 Accidents

By letter dated March 1, 1979, Alabama Power Company submitted a revised ECCS analysis for Farley Unit 1. This analysis used the February 1978 version of the Westinghouse ECCS Evaluation Model (WCAP-9220-P-A), which was reviewed and approved by the staff in its letter to Westinghouse dated August 29, 1978. By letter dated May 9, 1979, we transmitted our safety evaluation approving the ECCS analysis for Farley Unit 1.

By FSAR Amendment 72, the applicant updated the FSAR to incorporate this approved ECCS analysis for both Units 1 and 2. Unit 2 uses the same fuel as Unit 1 and has the same ECCS design. On this basis, we conclude that the ECCS analysis for Unit 2 as presented in FSAR Amendment 72 meets the applicable requirements of 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors," and Appendix K to 10 CFR Part 50, "ECCS Evaluation Models," and is therefore acceptable.

## 15.3 Offsite Dose Analyses

### 15.3.3 Fuel Handling Accident

By letter dated March 11, 1977, we requested the applicant to perform an analysis of the fuel handling accident inside containment. In FSAR Amendment Nos. 67 and 71, applicant provided the analysis and a description of modifications to the containment purge system, including seismically qualified charcoal filters.

The staff requirements for effective mitigation of a postulated fuel handling accident inside containment is to provide a means for prompt detection of any radioactive release followed by automatic containment isolation, or else to purge via an ESF-grade filtration system. In addition, the consequences of any activity released should be well within (less than 25 percent of) the 10 CFR Part 100 guideline values.

We find that this modified filter system meets the requirements of an ESF system and that the calculated doses from a fuel handling accident within containment are well within the guidelines of 10 CFR Part 100. We conclude that the proposed modification meets the staff requirements and is therefore acceptable. The assumptions used in our calculations are listed in Table 15-3a and the consequences shown in Table 15-6a.

## TABLE 15-3a

## FUEL HANDLING ACCIDENT ASSUMPTIONS (IN CONTAINMENT)

| | |
|---|---|
| Shutdown Time, hours | 100 |
| Total Number of Fuel Rods in the Core | 41,448 |
| Number of Fuel Rods Involved in the Refueling Accident | 264 |
| Power Peaking Factor | 1.65 |
| Iodine Fractions Released from Pool | |
| Elemental | 0.75 |
| Organic | 0.25 |
| Effective Filter Efficiency, percent | |
| Elemental | 90 |
| Organic | 30 |
| X/Q Values, seconds per cubic meter | |
| 0-2 hours @ 1260 meters | $6.5 \times 10^{-4}$ |
| 0-2 hours @ 3200 meters | $1.0 \times 10^{-4}$ |

## TABLE 15-6a

## POTENTIAL OFFSITE DOSES DUE TO DESIGN BASIS ACCIDENTS

| | Two-Hour Exclusion Boundary (1260 meters) | | Course of Accident Low Population Zone (3200 meters) | |
|---|---|---|---|---|
| | Thyroid (rem) | Whole Body (rem) | Thyroid (rem) | Whole Body (rem) |
| Fuel Handling (In Containment) | 45 | <1 | 7 | <1 |

## 17.0 QUALITY ASSURANCE

### 17.3 Quality Assurance Program

Since the issuance of Supplement No. 3 to the Safety Evaluation Report, the applicant has submitted amendments to its quality assurance program description for the operations phase of the Joseph M. Farley Nuclear Plant. Our review of the changes to the quality assurance program has verified that the criteria of Appendix B to 10 CFR Part 50 have been adequately addressed in Section 17.2 of the FSAR as amended through Amendment 72.

The staff has recently developed a revised procedure for conducting the review of safety-related structures, sytems, and components (Q-list) to which the quality assurance program applies. This review involves all branches that have responsibility for reviewing the FSAR and significantly enhances the staff's confidence in the acceptability of the Q-list. Staff re-review of the Q-list using the revised procedure is important for proper operation, maintenance, and modification of all safety-related items over the plant lifetime (40 years); however, its completion is not deemed to be necessary prior to granting authority to load fuel and perform low power tests, because the new item is not likely to require maintenance or modification in the short time internal of operation at low power. This re-review is presently under way and the results will be reported prior to full power operation.

## 22.0 TMI-2 REQUIREMENTS

### 22.1 Introduction

The accident at Three Mile Island (TMI) Unit 2 resulted in requirements which were developed from the recommendations of several groups established to investigate the accident. These groups include the Congress, the General Accounting Office, the President's Commission on the Accident at Three Mile Island, the NRC Special Inquiry Group, the NRC Advisory Committee on Reactor Safeguards, the Lessons-Learned Task Force and the Bulletins and Orders Task Force of the NRC Office of Nuclear Reactor Regulation, the Special Review Group of the NRC Office of Inspection and Enforcement, the NRC Staff Siting Task Force and Emergency Preparedness Task Force, and the NRC Offices of Standards Development and Nuclear Regulatory Research. The report NUREG-0660 entitled "NRC Action Plan Developed as a Result of the TMI-2 Accident" (Action Plan) was developed to provide a comprehensive and integrated plan for the actions now judged necessary by the NRC to correct or improve the regulation and operation of nuclear facilities. The Action Plan was based on the experience from the TMI-2 accident and the recommendations of the investigating groups.

In the development of the Action Plan (NUREG-0660), the NRC has transformed the recommendations of the investigating groups into discrete scheduled tasks that specify changes in its regulatory requirements, organization, or procedures. Some actions to improve the safety of operating plants were judged to be necessary before an action plan could be developed, although they were subsequently included in the Action Plan. Such actions came from the Bulletins and Orders issued by the Commission immediately after the accident, the first report of the Lessons-Learned Task Force issued in July 1979, and the recommendations of the Emergency Preparedness Task Force. Before these immediate actions were applied to operating plants they were approved by the Commission. The Joseph M. Farley Nuclear Plant Unit 1 is operating and has implemented applicable immediate actions.

Our review of TMI-2 requirements is based on the Commission policy statement issued on June 16, 1980, regarding the requirements to be met for current operating license applications. The requirements are derived from NRC's Action Plan (NUREG-0660) and are found in NUREG-0694, "TMI-Related Requirements for New Operating Licenses." The Joseph M. Farley Plant, Unit 2 was measured against the NRC regulations as augmented by these requirements.

The TMI-related requirements and actions for new operating licenses (NUREG-0694) are in four parts: (1) those required to be completed by the applicant prior to receiving a fuel loading and low-power testing license, (2) those required to be completed by the applicant prior to receiving a license to operate at appreciable power levels up to full power, (3) those the NRC will take prior to issuing licenses, either for fuel loading and low power testing or for full power operation, and (4) those required to be completed by a licensee prior to a specified date.

Chapter 22 of this supplement addresses the applicant's implementation of the TMI-related requirements in the Farley 2 plant. The applicant has provided a report, "Response to TMI-2 Action Plan," by its letter dated June 20, 1980, that gives its initial response to our requirements. During our review, we met with the applicant in Bethesda and at the Farley Plant site. The applicant has amended its initial response as a result of our review. Meeting results and applicant's letters relevant to our review are discussed in applicable sections of this supplement.

Each of the following sections corresponds to one of the four parts of NUREG-0694. Section 22.2 addresses fuel loading and low-power testing requirements. Section 22.3 addresses full power requirements. Section 22.4 addresses NRC actions. Section 22.5 addresses dated requirements. All of the requirements for fuel loading and low-power testing are addressed. In addition, those requirements for full power which have been completed are also addressed. The remaining requirements for a full power license will be addressed in Supplement No. 5 to our Safety Evaluation Report.

## 22.2 Fuel-Loading and Low-Power Testing Requirements

### I.A.1.1 Shift Technical Advisor

#### Requirement

A technical advisor to the shift supervisor shall be present on all shifts and available to the control room within ten minutes. Although minimum training requirements have not been specified, shift technical advisors should enhance the accident assessment function at the plant.

This requirement shall be met before fuel loading. (See NUREG-0578, Section 2.2.1.b, and letters of September 27 and November 9, 1979.)

#### 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 STAs 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 ten 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 or fuel loading date, whichever is later, and to have STAs, who have completed all training requirements, on duty by January 1, 1981. While minimum training requirements have not been specified for January 1, 1980, the STAs on duty at that time should enhance the accident and operating experience assessment function at the plant.

Discussion and Conclusions

Alabama Power Company (APCo) is currently providing an on-shift technical advisor for operation of Farley Unit 1. The NRC, in a letter from A. Schwencer to F. L. Clayton of APCo, dated April 3, 1980, concluded that the licensee had revised its administrative directives to specifically define the duties and responsibilities of the STA "and was in essential compliance with the short term Lessons Learned position on STAs." The applicant proposed that these same STAs will also service Farley Unit 2.

During normal plant operations, the five APCo employees who have been assigned to serve as STAs in an emergency situation will function as Shift Foremen - Inspecting. Each shift crew will have a Shift Supervisor, a Shift Foreman - Operating and a STA/Shift Foreman - Inspecting who will service both Farley units. The STA/Shift Foreman - Inspecting duties are to handle the tagging out of equipment, maintain an equipment status log, handle the processing of work orders, and to verify implementation of independent valve position verification requirements. The Shift Foreman - Operating is a licensed Senior Reactor Operator responsible to the Shift Supervisor for operation of the two nuclear units. As current plant procedures do not delineate the specific responsibilities assigned the STA/Shift Foreman - Inspecting, we are not sure what additional duties he might be assigned now or in the future.

In response to our request, APCo has agreed to modify its procedures prior to fuel loading to specifically describe these responsibilities and to include a specific statement that the STA shall not assume a command or control function or function as a Shift Supervisor or Shift Foreman - Operating.

During our review, we were concerned that as a result of his responsibilities as Shift Foreman - Inspecting, the STA might not learn of the existence of a slowly developing emergency condition in one of the units until too long after the condition was first recognized. APCo has agreed to augment its operating procedures to specify that the Shift Supervisor will notify the STA and request his immediate presence in the control room as soon as the Shift Supervisor learns of a significant abnormality or incipient emergency.

The NRC Office of Inspection and Enforcement will review the procedures after they are modified and will assure that the appropriate modifications as stated above are made prior to fuel load.

In our review, we ascertained that the STA will be informed of the results of evaluation of Licensing Event Reports and corrective action measures that might be useful to him in carrying out his emergency advisory role. A newly formed Systems Performance Group (SP Group) will assess operational data, including Licensing Event Reports. The procedures for the SP Group state that "The SP Group shall provide general engineering support for the STA function. When SP Group personnel performing operational assessment conclude that information exists which may be relative to the function of the STA, such information will be issued to the STAs."

Subject to confirmation by the Office of Inspection and Enforcement that the procedures have been modified to specify Shift foreman -Inspecting responsibilities and assignments as discussed above and that procedures have been modified to specify prompt calling of the STA to the control room upon learning of a significant abnormality or incipient emergency, we conclude that the requirements concerning STAs for fuel loading and low power testing have been met. In accordance with our Dated Requirement (I.A.1.1 in Section 22.5 of this supplement) APCo is required to have STAs who have completed all training requirements on duty by January 1, 1981.

### I.A.1.2 Shift Supervisor Administrative Duties

#### Requirement

Review the administrative duties of the shift supervisor and delegate functions that detract from or are subordinate to the management responsibility for assuring safe operation of the plant to other personnel not on duty in the control room.

This requirement shall be met before fuel loading. (See NUREG-0578, Section 2.2.1a, Item (4), and letters of September 27 and November 9, 1979.)

#### 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 that 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 deleg ted to other operations personnel not on duty in the control room.

Discussion and Conclusions

APCo has issued a management directive, dated December 12, 1979, which emphasizes the assignment of primary management responsibility to the shift supervisor. The directive is signed by F. L. Clayton, APCo Senior Vice President. APCo informed us that the directive will be reissued on an annual basis.

Administrative Procedure FNP-0-AP-16 "Corduct of Operation - Operations Group" has been revised to further clarify the responsibility of the shift supervisor. This procedure delineates the command decision authority of the shift supervisor in the control room relative to other plant management personnel or onshift operations personnel. It also delineates the responsibilities of the control room operators. Both the December 12, 1979 management directive and FNP-0-AP-16 require the shift supervisor to maintain, as a matter of highest priority, a broad perspective of operational conditions affecting the safety of the facility. He shall not become totally involved in any single operation when multiple operations are taking place.

The December 12, 1979 APCo management directive referenced above also covers the requirement that the shift supervisor remain in the control room during an emergency and transfer of control room command during routine operations. It states:

"The Shift Supervisor, until properly relieved, shall remain in the control room at all times during accident situations to direct the activities of the control room operators and perform the duties of Emergency Director. The on-call Emergency Director shall relieve the Shift Supervisor of Emergency Director duties. Only Senior Reactor Operator management personnel (shift supervisor or higher) are authorized to relieve the Shift Supervisor during accident conditions of his control room commander function.

If the Shift Supervisor is temporarily absent from the control room during routine operations, personnel authorized to assume the control room command function will be a licensed Senior Reactor Operator and Emergency Director trained. A formal relief will be conducted."

The training program for shift supervisors includes indoctrination in the plant administrative procedures which focus on and emphasize, as noted above, the shift supervisors' responsibility for safe operation of the plant and the management function that the shift supervisor is to provide.

The Manager of Nuclear Generation has fully participated in the review and revision of administrative procedures with specific emphasis on the delegation of miscellaneous duties to personnel other than the shift supervisor.

We have completed our review of shift supervisor administrative duties. Procedures have been revised to establish the authority of the shift supervisor and delineate a clear line of succession. Administrative duties have been reviewed, and where not safety related, reassigned to other personnel. The training program adequately emphsizes the shift supervisors' management function. Therefore, we conclude that this requirement has been met.

I.A.1.3 Shift Manning

Requirement

The following position is provided in a July 31, 1980 letter from the NRC Director, Division of Licensing, to all applicants for operating licenses and licensees of operating plants which stated the NRC's interim criteria for shift staffing and limitations on use of overtime:

> "At any time a licensed nuclear unit is being operated in Modes 1-4 for a PWR (Power Operation Startup, Hot Standby, or Hot Shutdown respectively) or in Modes 1-3 for a BWR (Power Operation, Startup, or Hot Shutdown respectively), the minimum shift crew shall include two licensed senior reactor operators (SRO), one of whom shall be designated as the shift supervisor, two licensed reactor operators (RO), and two unlicensed auxiliary operators (AO). For a multi-unit station, depending upon the station configuration, shift staffing may be adjusted to allow credit for licensed senior reactor operators (SRO) and licensed reactor operators (RO) to serve as relief operators on more than one unit; however, these individuals must be properly licensed on each such unit. At all other times, for a unit loaded with fuel, the minimum shift crew shall include one shift supervisor who shall be a licensed senior reactor operator (SRO), one licensed reactor operator (RO), and one unlicensed auxiliary operator."

Adjunct requirements to the shift staffing criteria stated above are as follows:

a. A shift supervisor with a senior reactor operator's license, who is also a member of the station supervisory staff, shall be onsite at all times when at least one unit is loaded with fuel. A shift supervisor with a senior reactor operator's license on both units and who is a member of the station supervisory staff shall be onsite at all times when both of the units are loaded with fuel.

b. A licensed senior reactor operator (SRO) shall, at all times, be in the control room from which a reactor is being operated. The shift supervisor may from time-to-time act as relief operator for the licensed senior reactor operator assigned to the control room.

c. For any station with more than one reactor containing fuel, the number of licensed senior reactor operators onsite shall, at all times, be at least one more than the number of control rooms from which the reactors are being operated.

d. In addition to the licensed senior reactor operators specified in a., b., and c. above, for each reactor containing fuel, a licensed reactor operator (RO) shall be in the control room at all times.

e. In addition to the operators specified in a., b., c., and d. above, for each control room from which a reactor is being operated, an additional licensed reactor operator (RO) shall be onsite at all times and available to serve as relief operator for that control room. As noted above, this individual may serve as relief operator for each unit being operated from that control room, provided he holds a current license for each unit.

f. Auxiliary (non-licensed) operators shall be properly qualified to support the unit to which assigned.

g. In addition to the staffing requirements stated above, shift crew assignments during periods of core alterations shall include a licensed senior reactor operator (SRO) to directly supervise the core alterations. This licensed senior reactor operator may have fuel handling duties but shall not have other concurrent operational duties.

In addition, licensees of operating plants and applicants for operating licenses shall include in their administrative procedures (required by license conditions) provisions governing required shift staffing and movement of key individuals about the plant. These provisions are required to assure that qualified plant personnel to man the operational shifts are readily available in the event of an abnormal or emergency situation.

The administrative procedures shall also set forth a policy concerning overtime work for the senior reactor operators, reactor operators, and shift technical advisor required by these interim criteria. These procedures shall stipulate that overtime shall not be routinely scheduled to compensate for an inadequate number of personnel to meet the shift crew staffing requirements. In the event that overtime must be used, due to unanticipated or unavoidable circumstances, the following overtime restrictions shall be followed:

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

(2) An individual shall not be permitted to work more than 24 hours in any 48-hour period.

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

(4) An individual shall not work more than 14 consecutive days without having two consecutive days off.

However, recognizing that circumstances may arise requiring deviation from the above restrictions, such deviation may be authorized by the plant manager or higher levels of management in accordance with published procedures and with appropriate documentation of the cause.

This requirement shall be met before fuel loading (see letter of July 31, 1980).

Discussion

APCo, in letters to the Director, Nuclear Reactor Regulation dated August 7 and 14, and September 8, 1980, and in telephone discussions with members of the NRC staff to clarify the information presented in these letters, has informed us that it will not have a sufficient number of senior reactor operators who are licensed on both of the Units to meet the current NRC licensed senior reactor operator requirements for operation of dual unit plants before April 1, 1981. For a dual unit plant with a common control room such as Farley, the requirements include two licensed senior reactor operators (SROs), each of whom is licensed on both units whenever one of the two units is in other than a cold shutdown condition. It also requires that one of these SROs be designated as the shift supervisor.

NRC-administered examinations to qualify for a Unit 2 senior reactor operator license were given in early August, 1980. As a result of these examinations, seven SROs licensed on Units 1 and 2 will be available for shift work at the time of fuel loading. At this time, there will also be available for shift work eight SROs licensed on Unit 1, only. This number of personnel is not sufficient to provide two double-licensed SROs on each shift, since a minimum of ten is required with eight-hour shifts.

APCo has scheduled six operating personnel to take the Unit 2 SRO examination in November 1980 and another two in February 1981. APCo's reference to April 1981 as the time by which it expects to meet the SRO shift manning requirement is based on the last of its Unit 2 SRO license candidates taking the examination in February and allowing five or six weeks following the examination for the NRC to grant the licenses.

We have explored in detail APCo plans [illegible]s for providing additional SROs who are licensed on both units on each operat[illegible]w. APCo plans to operate the plant with five operating crews that will be rotated on the day, night, and evening shifts. APCo has informed us that between fuel load of Unit 2 and April 1, 1981 (when it expects to fully meet the NRC requirement that two SROs licensed on both units be provided on each shift) it expects that the five operating crews will be manned by three SROs (as indicated in APCo's August 14, 1980 submittal) who are licensed on Unit 1 or Unit 2 as follows:

1. Provide one SRO that is licensed for the unit to which he is assigned, on each shift for each unit, designated as the shift supervisor for the unit to which he is assigned.

2. Assign a shift supervisor to the control room area whenever his unit is operating (Modes 1, 2, 3, and 4).

3. Assign an additional SRO (shift foreman-operating), licensed as a minimum on Unit 1, to each shift when either unit is operating. This SRO, as part of his responsibilities, will perform routine in-plant equipment inspections and walkdowns for Unit 2 (as well as for Unit 1) and will report the results to the Unit 2 shift supervisor.

Thus, three SROs will be assigned to each shift, one in addition to the two required, to compensate for the deficiency in meeting the new NRR requirement. The detailed SRO manning for five shifts is proposed as follows:

FUEL LOAD TO 1/81

| Shift Supervisor Unit 1 | Shift Supervisor Unit 2 | Shift Foreman Operating |
|---|---|---|
| 1. SRO Unit 1 | 1. SRO Unit 1 & 2 | 1. SRO Unit 1 & 2 |
| 2. SRO Unit 1 | 2. SRO Unit 1 & 2 | 2. SRO Unit 1 |
| 3. SRO Unit 1 | 3. SRO Unit 1 & 2 | 3. SRO Unit 1 |
| 4. SRO Unit 1 | 4. SRO Unit 1 & 2 | 4. SRO Unit 1 |
| 5. SRO Unit 1 & 2 | 5. SRO Unit 1 & 2 | 5. SRO Unit 1 |

1/81 TO 4/1/81

| Shift Supervisor Unit 1 | Shift Supervisor Unit 2 | Shift Foreman Operating |
|---|---|---|
| 1. SRO Unit 1 | 1. SRO Unit 1 & 2 | 1. SRO Unit 1 & 2 |
| 2. SRO Unit 1 | 2. SRO Unit 1 & 2 | 2. SRO Unit 1 & 2 |
| 3. SRO Unit 1 | 3. SRO Unit 1 & 2 | 3. SRO Unit 1 |
| 4. SRO Unit 1 & 2 | 4. SRO Unit 1 & 2 | 4. SRO Unit 1 |
| 5. SRO Unit 1 & 2 | 5. SRO Unit 1 & 2 | 5. SRO Unit 1 |

APCo has advised us that the shift crew staffing shown above is based on the following assumptions:

Fuel Load to 1/81

(1) No attrition will take place on the SRO staff.

(2) Shift vacancies due to vacation or sick time or unexpected attrition will be accomplished using either limited overtime of one or more of four non-shift persons who have Units 1 & 2 SRO licenses-two of which are staff jobs not SRO license designated.

1/1/81 to 4/1/81

(1) Four of the six candidates scheduled to take the Unit 2 SRO license examinations in November are licensed by January 1981.

(2) One SRO will be lost due to attrition.

(3) Shift vacancies due to vacation, sick time, or retraining will be accomplished using either limited overtime or one or more of four non-shift persons who have Units 1 & 2 SROs two of which are staff jobs not SRO designated.

If the examination passing rate is smaller than APCo predicts, or if there is attrition of staff, then some combination of overtime and interruption of training and vacations would be necessary to maintain station manning.

As indicated above, only two of the five shift crews are expected, by fuel loading, to have two double licensed SROs (licensed on both Units 1 and 2). However, each operating crew will have three SROs, two of which will be designated as shift supervisors, one more shift supervisor than is required by the NRC. APCo informed us that the shift supervisors have more experience and leadership ability than other SROs.

The third SRO on each crew will be assigned as the shift foreman - operating. Only one of the five shift crews will have a shift foreman - operating who is double licensed at the projected time of fuel loading. The other four shift crews will have shift foremen - operating who are licensed as an SRO on Unit 1 only. The shift foremen operating who are not double licensed will, however, have been trained in the minor differences between the two units. For all practical purposes, the two units are identical. Because of this, we believe that it is reasonable to expect that an SRO licensed on Unit 1 and trained in the minor differences between the two units will be capable of adequately carrying out all of the SRO functions on Unit 2 except those for which an SRO licensed on Unit 2 is required by the NRC regulations.

The shift supervisors are required to remain in the control room area unless relieved by an appropriately licensed SRO. This area includes restrooms. On those shift crews where the shift supervisor of Unit 2 is the only SRO licensed on Unit 2, he will be required to remain in the control room area at all times. He will have to rely on the shift foreman operating to maintain a visual cognizance and to advise him as needed on conditions and activities outside the control room. It is our view, based on the discussion above, that a shift foreman operating, even though licensed only on Unit 1, will be able to perform effectively as a reviewer and evaluator of both Unit 1 and Unit 2 systems and operations and that he will serve as an effective advisor to both Unit 1 and Unit 2 shift supervisors on matters concerning both units.

We conclude that APCo's proposal for manning shift crews with SROs as noted above will provide adequate senior operator oversight and supervision of the shift operators during the interim period between fuel load and the time when APCo has a sufficient number of double licensed SROs to provide two on every shift and is acceptable for the reasons summarized below:

- Unit 2 is for all practical purposes identical to Unit 1.
- As required by regulations, each unit will be manned by SROs and ROs who are licensed for that unit.
- The two-unit shift staffing is based on eight-hour shifts with some periodic use of overtime (as noted below) and will be instituted upon issuance of a license for Unit 2.
- The five-crew shift provides for an extra day shift which allows for training to be conducted.
- An extra SRO is provided on each shift.

By April 1, 1981, 24 ROs will be licensed on both Units 1 and 2. This will provide sufficient ROs to operate the plant and allow training to upgrade the ROs for SRO licenses. This should provide an adequate supply of SROs to meet staffing contingencies.

In its August 14, 1980 submittal, APCo made the following commitment with respect to overtime:

> "Alabama Power Company's policy is to maintain adequate manpower such that overtime will not be routinely scheduled in order to compensate for inadequate numbers of personnel to meet shift staffing requirements. Routine scheduling of overtime will not be employed for this reason at the Farley Nuclear Plant. There will be circumstances where periodic overtime must be utilized as a normal course of business even though shift staffing levels are adequate. These circumstances include the following: training those operators who are presently licensed only on Unit 1 for licenses on Unit 2; initial fueling of Unit 2 concurrent with operation of Unit 2; refueling of Unit 1 concurrent with Unit 2 startup operation; off-shift operator requalifications/upgrade training, and other circumstances in which additional operators are required on shift for off-normal operations.
>
> "When it is necessary to implement the periodic overtime discussed above, the following restrictions appropriately incorporated into Administrative Procedures will be utilized:
>
> "(A) An individual shall not be permitted to work more than 12 hours straight (not including shift turnover time).
>
> "(B) An individual shall not be permitted to work more than 24 hours in any 48-hour period (not including shift turnover time).
>
> "(C) An individual shall not work more than 72 hours in any seven-day period (not including shift turnover time).
>
> "(D) An individual shall not work more than 14 consecutive days without having two consecutive days off.
>
> "Recognizing that circumstances may arise requiring deviation from the above restrictions, such deviation may be authorized by the Plant Manager

or his designee in accordance with Administrative Procedures and with appropriate documentation of the cause."

We will require that when fully staffed with a sufficient number of double licensed SROs, APCo revise its procedures to fully meet the requirements of NRC's July 31, 1980 letter on shift manning and overtime.

With respect to the command function of the shift supervisors, it was not clear to us that APCo had provided for a clear delineation of the command decision authority of a lead shift supervisor to be in charge of both units in the event of an emergency. An APCo letter dated August 22, 1980, states:

"One of the two Shift Supervisors will be designated as the "Shift Supervisor in Charge" and will hold a Unit 1 and Unit 2 license. The Shift Supervisor in Charge will also be the interim Emergency Director who will function in the event of an emergency until the Plant Manager or other designated Emergency Director arrives on site. The Shift Supervisor in Charge will delegate the role of interim Emergency Director to the other Shift Supervisor if, in his judgment, the incipient or actual emergency involves principally Unit Number 1 and the other Shift Supervisor is licensed only on Unit Number 1. If the emergency affects both units, the Shift Supervisor in Charge will normally not make such delegation."

We find this to be acceptable. The Office of Inspection and Enforcement will confirm that APCo has established administrative procedures to satisfy this requirement prior to fuel load.

For licensed reactor operators (RO), the shift requirement is three, one licensed on each unit and one licensed on both units. For eight-hour shift operation, nine ROs licensed on Unit 2 or Units 1 and 2 are needed. APCo has indicated its goal is to operate with five shift crews which would require ten ROs. As a result of the recent examinations, nine ROs licensed on Units 1 and 2 will be available for shift work at the time of fuel loading. At this time, there will also be available for shift work eleven ROs licensed on Unit 1, only. This will permit forty-five man shifts per week to cover forty-two man shifts actually required double licensed. This will leave three shifts per week for requalification training and to accommodate contingencies.

APCo has scheduled three operations personnel to take the Unit 2 RO examination in November 1980. Twenty-two additional RO trainees are in the pipeline, with 12 scheduled to be examined in February 1981 and ten to be examined in September 1981.

We conclude that APCo's plan for manning shift crews with ROs, as noted above, will provide satisfactory reactor operator coverage during the interim period between fuel load and April 1, 1981, at which time APCo expects to have a sufficient number of ROs licensed on Unit 2. However, in the interim period, APCo does not have a surplus of personnel (e.g., it assumes that all three of the RO examinees will pass the November examination) and any shortage may be further aggravated by attrition or illness beyond that expected. APCo has recently informed us that there are a number of potential remedies they believe are available to compensate for any shortfall of ROs that may develop. APCo has stated that the required RO staffing can be accommodated by (1) use of licensed personnel who currently do not hold jobs required to have licenses, are not in the operating or management chain, nor involved in training instruction, (2) judicious and limited use of overtime, and (3) a cutback on vacations and training.

Five STAs are available for shift operation, which is acceptable (see Section I.A.1.1). Twenty-two health physics technicians are available for shift operation, which is acceptable.

Conclusions

We have reviewed the information on shift manning and overtime provided by APCo in the SAR as amended, and the submittals dated August 7, 14, and 22, 1960, and September 8, 1980 and compared the information with the applicable portions of 10 CFR 50.34(b)(7), 10 CFR 50.54(i), (j), (k), (l), (m), 10 CFR Part 55, and the Interim Criteria dated July 31, 1980.

For the long term, the licensee proposes to operate in accordance with the regulations and the Interim Criteria; our evaluation shows that his program complies with the requirements and is acceptable. For the next few months, however, the licensee will have too few double licensed SROs to comply with the Interim Criteria, and has proposed an acceptable plan to compensate by using three SROs on each shift instead of the two required by the Interim Criteria. In any case, a licensed SRO would be assigned to the plant to perform routine in-plant equipment inspections and walk-downs.

With respect to ROs, for the next few months, APCo does not have a surplus of ROs licensed for Unit 2 but, does have an adequate number to provide satisfactory coverage. To compensate for any shortfall that may develop, APCo has proposed an acceptable contingency plan, as noted above.

We conclude that, for the long term, APCo has made acceptable plans for increasing the total numbers of licensed operators and senior operators to be available for shift manning.

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

Requirement

All reactor operator license applicants shall take a written examination with a new category dealing with the principles of heat transfer and fluid mechanics, a time limit of nine hours, and a passing grade of 80 percent overall and 70 percent in each category.

All senior reactor operator license applicants shall take the reactor operator examination, an operating test, and a senior reactor operator written examination with a new category dealing with the theory of fluids and thermodynamics, a time limit of seven hours, and a passing grade of 80 percent overall and 70 percent in each category.

These requirements shall be met before fuel loading. (See letter of March 28, 1980.)

Discussion and Conclusion

We informed the Applicant that the scope and criteria for licensing examinations would be changed . . .ted in the above requirement.

Further, have informed Farley management that individuals licensed on Unit 1 who fail the examination on Unit 2 will be prohibited from performing licensed duties on Unit 1 until they have been requalified.

These requirements will be implemented for operators of Farley Unit 2.

I.B.1.2 Evaluation of Organization and Management Improvements of Near-Term Operating License Applicants

Requirement

The licensee organization shall comply with the findings and requirements generated in an interoffice NRC review of licensee organization and management. The review will be based on an NRC document entitled "Draft Criteria for Utility Management and Technical Competence." The first draft of this document was dated February 25, 1980, but the document is changing with use and experience in ongoing reviews. These draft criteria address the organization, resources, training, and qualifications of plant staff, and management (both onsite and offsite) for routine operations and the resources and activities (both onsite and offsite) for accident conditions.

Establish an onsite group, independent of the plant staff, that is assigned to perform independent reviews of plant operational activities and that has a capability for evaluation of operating experiences at nuclear power plants.

Organizational changes are to be implemented on a schedule to be determined prior to fuel loading.

Position

Corporate management of the utility-owner of a nuclear power plant shall be sufficiently involved in the operational phase activities, including plant modifications, to assure a continual understanding of plant conditions and safety considerations. Corporation 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 organizational arrangement are:

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

The assignment of responsibility for the safe operation of the nuclear power plant(s) to an upper level executive 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 to evaluate and assess the plants' operating experience and performance.

Discussion and Conclusion

In evaluating the adequacy of the APCo organization and management for operation of the Farley Unit 2, NRC staff members met and held discussions with APCo corporate management in Bethesda, Maryland, on June 24, 1980 and traveled to the Farley Plant and to the corporate offices of Birmingham, Alabama, on June 30 through July 2, 1980, where they met and held discussions with members of APCo's Farley plant staff and corporate management staff. The information presented here is based on the oral discussions as well as information that has been formally submitted to the NRC by APCo. As a general guideline for this evalution, we used the "Draft Criteria for Utility Management and Technical Competence," dated February 25, 1980, developed by the NRC staff.

APCo has restructured its corporate organization to place all nuclear operations under a single individual, with the title Vice President Nuclear Generation and who has no functional responsibility for activities related to non-nuclear plants. The designee for this position, Mr. R. P. McDonald, holds a Bachelor of Science degree in Engineering from the U.S. Naval Academy, and has had extensive experience, as a naval officer, in the operation of reactor plants on nuclear submarines. In addition, he was the APCo Corporate Manager of Operations Quality Assurance for three years and was Vice President - Power Supply Services, where he managed an organization that included project engineering support to the Farley Nuclear Plant in areas of design, construction, maintenance, procurement, and technical liaison. Mr. McDonald reports to Mr. F. L. Clayton, Senior Vice President, who has had 33 years of experience with the company - 20 of which are nuclear related.

Mr. McDonald is actively involved in Farley Plant operational activities. He reviews and approves the qualification requirements for all plant staff positions and for all offsite staff positions. He reviews and certifies the qualifications of plant personnel in the categories of managers, lead professional-technical personnel and shift supervisors. He approves the technical content of all plans developed, submitted, and implemented in accordance with regulatory requirements (e.g., industrial security plan, quality assurance plan, plant staff training program). He periodically assesses the staff training and quality assurance program. He reviews plant inspection reports. He reviews all deficiencies and violations of plant procedures and technical specification requirements. He serves as the

Vice Chairman of the Nuclear Offsite Review Board which meets quarterly, and he appoints and receives reports from Operation Evaluation Teams which make special evaluations of plant operations and staff performance.

Corporate managers reporting to Mr. McDonald include a General Manager of Nuclear Generation (Mr. H. O. Thrash), a Manager of Nuclear Engineering and Technical Support (Mr. O. D. Kingsley), a Manager of Safety Audit and Engineering Review (Mr. J. W. McGowan), and a Manager of Design and Construction Quality Assurance (Mr. W. C. Petty, Jr.). All of these managers hold Bachelor of Science degrees in an engineering discipline and have substantial nuclear power related experience that they accrued in the U.S. Navy's nuclear submarine programs and/or in working on the Farley Plant. This offsite corporate nuclear organization has a tehcnical staff of approximately 50 employees. It provides general management oversite of Farley Plant activities in areas of operating abnormalities, maintenance problems, design changes and modifications, licensing, physical security, and emergency planning. This APCo organization is supplemented by the technical staff of Southern Company Services which serves in an architect engineering and licensing advisory role within the Southern Company (of which APCo is part). Approximately 40 members of the Southern Company Services technical staff are permanently dedicated to the support of Farley Plant activities. In addition, APCo has standing contracts with Bechtel Power Corporation and Westinghouse Electric Corporation to provide technical assistance as requested in the areas of general architect-engineering and nuclear steam systems support.

The APCo offsite technical staff is not structured to perform detailed designs and technical analyses in support of the Farley Plant. Instead, it is organized to handle the management and engineering coordination of these support activities. Detailed design engineering and technical support assistance for the Farley Plant is obtained from Southern Company Services, Bechtel Power Corporation and Westinghouse Electric Corporation. The Nuclear Engineering and Technical Support group under Mr. O. Kingsley is the APCo interface with these organizations and manages and coordinates the contracting and performance of these support activities.

APCo informed us that in the event of an accident at the Farley Plant, the members of its offsite technical staff that go to the site will not act in an advisory role to the plant staff but act principally as coordinators to obtain the expert assistance as needed from Southern Company Services, Bechtel Power Corporation, and Westinghouse Electric Corporation. APCo has stated that since these staff members do this type of coordination as a part of their normal day to day job they need no special training with respect to the Farley Station (i.e., plant problems, design modifications, operation procedure changes, etc.). We agree that staff members performing such coordination would not require such special training on plant status. APCo informed us that while it has not made any agreements with other utilities concerning the pooling of resources for use in emergencies, it does belong to the Institute for Nuclear Power Operations (INPO) group and will avail itself of any emergency resources that are available through INPO.

APCo has proposed that instead of providing a group onsite to perform independent (of the plant staff) reviews of plant operational activities, it will accomplish the tasks that such an independent group might perform by using a combination of organizations. The first and most substantive of these groups is a newly formed Systems Performance Group which will perform reviews of plant operational experience to identify and resolve existing or potential plant operational problems having significant safety consequences. This group will also determine areas where changes in design procedures or practices could improve operational reliability and more effectively mitigate consequences of accidents, malfunctions, and errors. As currently structured, this group is not independent of the plant staff; it reports to the plant manager. Another of these groups is a newly formed entity referred to as Operations Evaluation Teams whose members are drawn from the corporate office or other offsite locations and who are appointed by and report to the Vice President - Nuclear Generation. These teams are to go to the site, as assigned, to evaluate plant operations and assess plant staff performance as they pertain to safety. We were informed that the first of these teams has already made two evaluation visits to the site and that it is a goal to have such teams go out about once each month. The third organization that is proposed to assist in this review of operational activities is the operations quality assurance organization which has been reconstituted as the Safety Audit and Engineering Review Group. This group will have a multidisciplined staff of engineers located onsite and reporting offsite to the Corporate Manager of Safety Audit and Engineering Review. By letter dated August 8, 1980, applicant indicated that this group will (1) verify that the review and evaluation to be performed by the other groups are performed and are handled in accordance with APCo policies and procedures, (2) perform independent reviews of specific plant operational activities, and (3) perform onsite quality assurance work.

We have orally informed APCo that we are concerned that by having the independent engineering review and evaluation of operational activities performed by the same onsite group that performs the QA activities, the QA activities might dilute the engineering review and evaluation effort. APCo informed us that it would have six multidisciplined engineers assigned to this group, that only about 20 percent of an individual's time might be devoted to QA work, and APCo is confident that this onsite group will adequately perform all the required independent review and evaluation activities that APCo has listed for this group in its August 8, 1980 submittal to the NRC. While we have expressed a concern, as noted above, regarding the potential for QA efforts diluting the independent engineering review and evaluation effort, we believe that if sufficient and continual management attention is given to this concern, the approach as proposed by APCo can meet the NRC objectives for onsite independent engineering review and evaluation of plant operational activities. Therefore, we find this approach to be acceptable at this time. However, we intend to review this activity at the Farley plant in about a year, as we plan to do at all other licensed plants, to assure that the onsite group is functioning properly and to determine if some changes are needed to make it more effective. We will include requirements for the functioning of this onsite group in the Farley 2 Technical Specifications.

APCo has a formal program in place for review of Licensee Event Reports (LERs) and for assuring feedback of operating experience information to its operating staff. This is discussed further in Item I.C.5 of this supplement entitled "Procedures for Feedback of Operating Experience to Plant Staff."

With regard to the health physics (HP) staffing and organization, we found five functional groups--Health Physics, Waste and Decon, Counting Room and Emergency Planning, ALARA, and

Chemistry--reporting to the Chemical and Health Physics (C&HP) Supervisor who is the Radiation Protection Manager (RPM) as defined in Regulatory Guide 1.8, "Personnel Selection and Training." Each of these groups was headed by a Supervisor or Foreman. There were individuals within the C&HP group qualified to act as RPM in the absence of the C&HP Supervisor and to provide technical assistance in routine and accident situations. Technicians and foremen were qualified by specialty, either chemistry or health physics as required by Regulatory Guide 1.8, "Personnel Selection and Training." Due to a recent reorganization that resulted in promotions of several HP technicians to foremen positions, approximately half of the health physics technician positions were filled with contractors during normal oprations. APCo recruiting records showed that approximately 14 additional individuals were to be hired into HP technician positions by the end of summer, with recruiting continuing for additional openings. It is APCo's intent to have sufficient staff so as not to require contract technicians during normal operations.

Because the HP supervisors, foremen, and technicians are functioning separately from chemistry, because they are trained and qualified as HP technicians specifically (not as Chemistry and also HP technicians), and because the inspection history at the plant has shown this organization to function effectively, we find this organization acceptable. We required, and applicant has agreed, that the Farley Unit 2 Technical Specifications will show the separation of health physics and chemistry at the levels reporting to the C&HP Supervisor.

The plant staff organization in Section 13.1 of the FSAR shows the C&HP Supervisor reporting directly to the Technical Superintendent with a dotted line reporting to the Assistant Plant Manager. Applicant's representatives stated that this dotted line represented the C&HP Supervisor's authority to report directly to the Assistant Plant Manager in matters of radiation protection when necessary. Licensee representatives stated that the Technical Superintendent provided management and assistance to the C&HP Supervisor on personnel and administrative matters and interfaced with other plant staff on behalf of the C&HP Supervisor when necessary. Licensee management stated that the management reporting system as now implemented functioned effectively and that requiring the C&HP Supervisor to report directly to the Assistant Plant Manager for all matters would dilute the Assistant Plant Manager's time with administrative and personnel activities, would reduce his time available for other duties and would, therefore, detract from the safe operation at the plant. We reviewed the methods of communication between the C&HP Supervisor, the Technical Superintendent, and the Assistant Plant Manager and found them acceptable. Because the C&HP Supervisor effectively reports to the Assistant Plant Manager for substantial matters of radiation protection and because the inspection record for the plant shows this arrangement to function effectively, we find the organization as functioning acceptable. We required, and applicant has agreed, that the Technical Specifications will show the organization as it is functioning.

With regard to organization and staffing for emergencies, applicant's representatives stated that their Emergency Plan was being revised in accordance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," and that the revised plan would be submitted to the NRC for review and approval shortly. (See Section III.A.1.1 of this section for our evaluation of emergency preparedness plans.) Applicant's representatives stated that they have increased health physics staffing beyond that required by NUREG-0654, so that there is now a health physics foreman plus technicians for each shift.

We conclude that APCo's organization and management improvements related to TMI lessons learned are substantial and provide reasonable assurance that appropriate and due concern for safety will be exercised in the operation of Farley Plant Unit 2.

I.C.1 Accident Analysis and Procedure Revision

Requirement

Analyze small-break loss-of-coolant accidents over a range of break sizes, locations, and conditions (including some specified multiple equipment failures) and inadequate core cooling due to both low reactor coolant system inventory and the loss of natural circulation to determine the important phenomena involved and expected instrument indications. Based on these analyses, revise as necessary emergency procedures and training.

These requirements shall be met before fuel loading. (See NUREG-0578, Sections 2.1.3b and 2.1.9, and letters of September 27 and November 9, 1979.)

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 Order 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 of 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 2.1.3b 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 the water level being below the top of the core 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 the loss of reactor coolant to the extent that the water level in the reactor vessel drops below the top of the core, and prevention of more serious accidents.

The information derived from the preceding analyses shall be included in the plant emergency procedures and operator training. 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 LOF' 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 . 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 ^ rs 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 Bulletin 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 Farley Unit 2 plant and we conclude that the review and approval of the small-break LOCA analyses and guidelines apply in total to the Farley, Unit 2 plant.

By letter dated June 30, 1980, the licensee submitted procedures for loss-of-coolant accident (including small breaks), inadequate core cooling, anticipated transients without trip, steam generator tube rupture, and loss of main feedwater. These procedures are required to be reviewed by the staff and corrected by the applicant prior to full power operation. (See requirement I.C.8 of Part 2 of NUREG-0694.)

Based upon our review to date of the procedures submitted by the licensee, we find they are generally consistent with the guidelines for Westinghouse plants. There are a number of minor inconsistencies with specific details of the guidelines and some instructions to the operator are vague. These matters are being discussed with the licensee. Our detailed comments on the procedures were transmitted to the licensee, and we met with the licensee to discuss procedure revisions required for technical and sequential adequacy. Selected revised emergency procedures will be walked through a simulator and the plant and further changes made, if necessary. The revisions described in the Conclusions Regarding Existing Instrumentation in II.F.2 of Section 22.2 of this supplement will be made. The resulting revised emergency procedures will be incorporated into the plant training program and operating procedures.

As we stated above, the selected procedures in their current state are generally consistent with the guidelines for Westinghouse plants. These procedures are in place at the plant and are available for any emergency. Since the procedures deal primarily with the cooldown of the reactor and steam cycle and since the decay heat load at 5% of rated power is minimal, we find the procedures in their current state to be acceptable to support operation up to 5% power for low power testing and training. We will report our evaluation of the completed procedures in Supplement 5 to our Safety Evaluation Report, prior to full power operation.

I.C.2 Shift Relief and Turnover Procedures

Requirement

Revise plant procedures for ift relief and turnover to require signed checklists and logs to assure that the operating taff (including auxiliary operators and maintenance personnel) possess adequate knowledge of critical plant parameter status, system status, availability, and alignment.

This requirement shall be met before fuel loading. (See NUREG-0578, Section 2.2.1c, and letters of September 27 and November 9, 1979.)

Discussion and Conclusions

Farley Nuclear Plant Administrative Procedure FNP-0-AP-16 was modified for Farley Unit 1 to implement this change in response to this requirement for operating plants. This change was reviewed and found acceptable for Farley Nuclear Plant Unit 1 as documented in the NRC's April 3, 1980 letter from A Schwencer to F. L. Clayton of APCo. This revised procedure is also applicable to and acceptable for operation of Farley Nuclear Plant Unit 2. We will require implementation in the license.

I.C.3 Shift Supervisor Responsibilities

Requirement

Issue a corporate management directive that clearly establishes the command duties of the shift supervisor and emphasizes the primary management responsibility for safe operation of the plant. Revise plant procedures to clearly define the duties, responsibilities and authority of the shift supervisor and the control room operators.

These requirements shall be met before fuel loading. (See NUREG-0578, Section 2.2.1a, Items 1, 2, and 3, and letters of September 27 and November 9, 1979.)

Discussion and Conclusion

APCo corporate management issued a directive and modified Farley Nuclear Plant Administrative Procedure FNP-0-AP-16 for Unit 1 in response to this requirement. This directive and procedure revision were reviewed and found acceptable for Farley Nuclear Plant Unit 1 as documented in the NRC's April 3, 1980 letter from A. Schwencer to F. L. Clayton of APCo. This directive and revised procedure are also applicable to and acceptable for operation of Farley Unit 2.

I.C.4 Control Room Access

Requirement

Revise plant procedures to limit access to the control room to those individuals responsible for the direct operation of the plant, technical advisors, specified NRC personnel, and to establish a clear line of authority, responsibility, and succession in the control room

This requirement shall be met before fuel loading. (See NUREG-0578, Section 2.2.2a, and letters of September 27 and November 9, 1979.)

Discussion and Conclusions

Farley Nuclear Plant Administrative Procedure FNP-0-AP-16 was modified for Unit 1 to implement this change in response to this requirement for operating plants. This change was reviewed and found acceptable for Farley Nuclear Plant Unit 1 as documented in the NRC's April 3, 1980 letter from A. Schwencer to F. L. Clayton of APCo. This revised procedure is also applicable to and acceptable for operation of Farley Nuclear Plant Unit 2.

I.C.5 Procedures for Feedback of Operating Experience to Plant Staff

Requirement

Review and revise, as necessary, procedures to assure that operating experiences are fed back to operators and other personnel.

This requirement shall be met before fuel loading.

Position

Each licensee shall review its procedures and revise them, as necessary, to assure that important operating experience originating both within and outside the organization is continually provided to operators and other personnel and is incorporated into training and retraining programs. These procedures shall assure that high-priority matters are dealt with promptly while keeping operating personnel from being deluged with paper or instructions on less important matters to the detriment of their overall proficiency.

Discussion and Conclusion

A newly formed plant System Performance Group has been assigned the responsibility for engineering evaluation of the operating history of the Farley Plant (equipment failures, design problems, operation errors, etc.) and Licensee Event Reports (LER) from other plants of similar design, with dissemination of the results of such evaluations to other members of the plant staff. Reports of significant events from other plants, vendor notifications and regulatory notifications are reviewed and evaluated in accordance with appropriate plant procedures. Procedures specify plant superintendents and supervisors as recipients of pertinent information and they distribute it as required. In addition, procedures require that information important to the STA performing his job be sent directly to him by the System Performance Group.

Procedures also specify how operating personnel are to be informed of plant modifications, procedure revisions and license changes that have operational or safety significance. APCo informed us that it has instituted a program whereby each shift crew will be given training (as a crew) after each four weeks of operation (i.e., four weeks on operating shift work, then one week of training). Operating crew members will be informed of all new information considered important to safety (including LER evaluations) during these training sessions.

Based on our discussions at the plant site with plant staff and operating crew members and a review of plant procedures and other information submitted by APCo, we have concluded that important operating experience originating both within and outside the organization will be continually and appropriately provided to operators and other personnel and is incorporated into training and retraining programs.

I.C.7 NSSS Vendor Review of Procedures

Requirement

Obtain nuclear steam supply system (NSSS) vendor review of low-power testing procedures to further verify their adequacy.

This requirement must be met before fuel loading.

Discussion and Conclusions

The applicant has submitted the low-power physics test procedures to Westinghouse for review and Westinghouse comments have been received at the Farley Plant. We require that comments also be provided by Westinghouse for the augmented low power tests (Item I.G.1 of this section). The Office of Inspection and Enforcement will verify fulfillment of this requirement prior to fuel loading.

I.D.1 Control Room Design

Requirement

Perform a preliminary assessment of the control room to identify significant human factors deficiencies and instrumentation problems and establish a schedule approved by the NRC for correcting deficiencies.

This requirement shall be met before fuel loading.

Discussion and Conclusions

As part of the staff actions following the TMI-2 accident, the staff requires 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 be completed by the end of 1982. As an interim measure, Alabama Power Company (APCo) was required to perform a preliminary design assessment of the Unit 2 control room to identify significant human factors deficiencies and instrumentation problems. Results of APCo's assessment are provided in a June 10, 1980 letter to the NRC. The NRC staff and its consultant followed up the APCo assessment with a 5-day onsite control room audit. The review included the assessment of control and display panel layout, annunciator design, labeling of panel components, and the usability and completeness of selected emergency procedures. The 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. 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. Alarm displays have good visibility and are easily readable from the main control area. Alarm displays are located over appropriate system controls and displays. Physical design of the vertical boards and the control console reflects consideration of human anthropometry with alarm panels tilted down for normal visual access and all controls on bench boards accessible to all operators.

The more significant human factors related deficiencies in the Farley Unit 2 control room which were identified during the control room audit are as follows:

1. Control room noise. Noise measurements taken at 3 locations throughout the control room ranged from a low of 66 dB(A) to a high of 76.5dB(A).

2. Annunciator Prioritization. With the exception of the first out, annunciators lack prioritization by color.

3. Annunciator Audible Alarms. Alarms levels are barely audible above ambient noise levels.

4. Accidental Actuation. Switches near the edge of the console are subject to accidental actuation.

5. Color Coding. Color of demarcation tape has no significance and the tape is not a permanent installation. There are too many colors to allow for easy system discrimination.

6. Operator Aids. All operator aids should be made permanent (i.e., yellow tape used to flag important meters).

7. Labeling. Components, systems, subsystems and panels, lack panels, and some components are mislabeled.

8. Process Computer. One of two cathode ray tubes is inoperable, alarm printer paper feed is not operating properly.

9. Controllers. All reverse acting valve controllers (valve opens on decreasing control signal) should be either changed, oriented, or labeled for consistant open/close or increase/decrease positions.

10. Tolerar.e ranges. No normal or out-of-tolerance ranges are indicated on meters.

11. Emergency Diesel Generator. There are no provisions for lamp test on diesel generator status lights; also they are poorly illuminated.

12. Annunciators. Bulb change subjects the control room operator to a shock hazard.

The above deficiencies are those which we believe could cause the operator to take erroneous actions under stressful conditions that may arise during an abnormal event. These actions could initiate a transient or could exacerbate the operator's response to an abnormal event already underway. However, none of these deficiencie offer any significant safety risk to fuel loading and low power testing because there are larger thermal margins to the onset of exceeding fuel design limits and safety limits during low power operation than during full power operation.

In order to correct these deficiencies, APCo and the staff have agreed that except as noted in Item 10, the following solutions will be implemented prior to escalation beyond five percent power:

1. Control Room Noise. The background noise originated from the air conditioning ducts located in the control room ceiling. APCo will relocate the volume control diffusers and rebalance the flow rates throughout the system. This relocation and rebalancing should reduce the background noise to an acceptable level (less than 65 dB(A)).

2. Annunciator Prioritization. APCo will develop a list of annunciators that should receive more operator attention. These annunciators will be prioritized by color.

3. Annunciator Alarms. APCo will increase the main control board, balance of plant and emergency power board annunciator alarm levels to 6-8dB(A) above the ambient noise level. Reduction of the background noise will result in more audible alarm levels.

4. Accidental Actuation. APCo will extend the horizontal portion of the main control board to prevent inadvertent operation of controls.

5. Color Coding. APCo will review the color utilized for demarcation. A color will be used that provides significance and the tape will be permanently installed. Colors used for system discrimination will be reviewed in order to reduce the number of colors and to increase system discrimination.

6. Operator Aids. All operator aids will be made permanent.

7. Labeling. APCo will review the main control board and will relabel as required for easy identification and for consistency.

8. Process Computer. APCo will correct the paper feed problem and ensure that both main control room cathode ray tubes are operable. A hood will be added to the cathode ray

tube located on the main control board reactor panel to reduce the glare. A cross index of data point addresses will be provided for the operator.

9. Controllers. All reverse acting controllers will be consistently labeled (open/close).

10. Tolerance Ranges. APCo will provide for normal, alert and alarm ranges for the significant main control room meters. As a first priority, meters identified in emergency procedures will be completed before exceeding 5 percent power. Other signficant meters will be completed as information is available, but will be finished before completion of the initial refueling outage.

11. Emergency Diesel Generator. A program for lamptesting the diesel generator status lights is being developed. The illumination level will be increased.

12. Annunciators. The shock hazard to the control room operator will be eliminated by covering the exposed wires.

In addition to the above listed deficiencies, our review identified a number of minor deficiencies, the correction of which we believe will enhance effective, efficient, and safe operator actions for long-term operation. In many cases the deficiencies identified by the staff had been previously identified by Alabama Power Company during their control room review and in many cases plans are now in process to rectify these deficiencies. However, to ensure that the additional modifications are made in the most efficient and effective manner to the control room, the staff will not require implementation of the minor design deficiencies until Alabama Power Company has completed the detailed control room design review to be required of all operating reactors. As part of this design review we will require APCo to evaluate the benefits of installing data recording and logging equipment in the control room to correct the deficiencies associated with trending of important parameters on strip chart recorders in use at most nuclear power plants.

Based on the findings of this review, it is the staff's judgment that the implementation of the above list of corrective actions will contribute to lessen the probability of operator errors during emergency operations. The Office of Inspection and Enforcement will verify completion of these corrective actions. We may require additional improvements to be made as a result of the licensee's detailed control room design review. We expect the completion of the detailed review and most corrective actions to be implemented early in 1982.

I.G.1 Training During Low-Power Testing

Requirement

Define and commit to a special low-power testing program approved by NRC to be conducted at power levels no greater than 5 percent for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and to provide supplemental training.

This requirement shall be met before fuel loading.

Position

The TMI Task Action Plan states that new operating licensees will conduct a set of low power tests to increase the capability of shift crews and ensure training in plant evolutions and off-normal events. Near-term operating license facilities will be required to develop and implement intensified exercises during the low power testing program. This may involve the repetition of startup tests on different shifts for training purposes.

Prior to issuance of a low power license, each applicant must commit to conduct a low-power test program similar to that conducted at Sequoyah Unit 1 and North Anna Unit 2.

The low-power test program conducted at Sequoyah Unit 1 consisted of nine tests, eight 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 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).

Each applicant for a full power operating license must perform tests similar to the above tests conducted at Sequoyah except for Test 8 and Test 9b. Test 8 may be deleted if training for each operator is provided on a simulator that has been updated as necessary using Westinghouse and TVA test data collected during performance of Test 8 at Sequoyah. Test 9b must be performed but may be modified and deferred until completion of the power-ascension program and manufacturer's acceptance test, provided that it is performed immediately following the manufacturer's acceptance test. Other exceptions to the test program will be considered if unique, plant-specific differences could cause one or more tests conducted at North Anna and Sequoyah to be unsafe.

Discussion and Conclusions

By letter dated July 17, 1980, the applicant committed to performing a special low-power test program which will consist of Tests 1 through 7 and 9a prior to exceeding five percent of rated power. In addition, the applicant committed to perform Test 9b after completion of the power ascension program and the Westinghouse NSSS acceptance tests. Chapter 14 of Farley Unit 2 FSAR will be modified to describe this test. In lieu of performing Test 8, the applicant has committed to providing Farley Nuclear Plant operators training on a simulator that has been modified using test data collected by Westinghouse and TVA at Sequoyah.

It is concluded that the low power test program described in the applicant's letter dated July 17, 1980, will satisfy Requirement I.G.1. Prior to conducting these tests, the applicant must submit a test description, procedures and safety analysis for review and approval by the staff. Applicant has agreed to provide this information by September 1, 1980, based on its scheduled start of the tests on October 1, 1980.

II.B.4 Training for Mitigating Core Damage

Requirement

Develop a training program to instruct all operating personnel in the use of installed systems, including systems that are not engineered safety features, and instrumentation to monitor and control accidents in which the core may be severely damaged.

This requirement shall be met before fuel loading.

Position

The staff requires that the applicant develop a program to ensure that all operating personnel are trained 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 of 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 $H_2$ generation during an accident; other sources of gas (Xe, Kr); techniques for venting or disposal of non-condensibles.

2. $H_2$ flammability and explosive limit; sources of $O_2$ in containment or Reactor Coolant System.

Discussion and Conclusions

By letter dated July 29, 1980, the applicant submitted an outline of a training program to meet the requirements of II.B.4. The program, "Training for Mitigating Core Damage," was developed by Alabama Power Company to ensure that all licensed operating employees are properly trained to use information available from installed plant systems to recogr ze, control, and mitigate an accident in which the core is severely damaged. This training supplements the existing training program and consists of 15 hours of classroom instruct' n, followed by an examination at the conclusion of the program. Personnel attending the program will include licensed operators, licensed senior operators, emergency directors required by the emergency plan, shift technical advisors, and plant instructors associated with training for mitigating core damage. In addition, other non-licensed operating personnel will be trained in those parts of the program that are applicable to their job func'ions. Training will be completed prior to operation above 5 percent power. The Office of Inspection and Enforcement will verify that training has been completed prior to operation above five percent power.

Based on the foregoing, we conclude that the applicant has met the requirement for fuel loading and low-power testing.

II.D.1 Relief and Safety Valve Test Requirements

Requirement

Describe a test program and schedule for testing to qualify reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.

This requirement shall be met before fuel loading. (See NUREG-0578, Section 2.1.2, and letters of September 27 and November 9, 1979.)

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, "Standard Format and Content of Safety Analysis Reports."

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.

Discussion and Conclusions

By letter dated July 16, 1980, we requested applicant to provide commitments to fulfill this requirement.

The applicant submitted its response by letter dated July 23, 1980. The applicant has stated that it will participate in the EPRI/NSAC program to conduct performance testing of PWR relief and safety valves and associated piping and supports. The applicant has referenced the proposed EPRI program ("Program Plan for the Performance Verification of PWR Safety/Relief Valves and Systems," dated December 13, 1979) for the performance testing of these valves.

A description of the test program was provided to the NRC by EPRI in December 1979. We will review this program and schedule to ensure that the NUREG-0578 requirements are met. Preliminary discussions with EPRI also indicate that meeting the clarified requirements of NUREG-0578 is feasible. The applicant has committed that by July 1, 1981 it will submit to the NRC evidence, supported by a summary of the test data, of the operability of the safety and relief valves installed at the Farley plant. However, no commitment was made regarding testing of block valves, as requested in our July 16 letter.

The staff is currently preparing more definitive requirements to be sent to all applicants and licensees. We conclude that the commitment provided by the applicant in its July 23 letter is acceptable for a fuel-load and low-power testing license. The completion of the tests and demonstration of applicability to specific plants is a dated requirement. We will report on the applicant's response to our new requirements in a future supplement to the SER.

II.D.3 Relief and Safety Valve Position Indication

Requirement

Install positive indication in the control room of relief and safety valve position derived from a reliable valve position detection device or a reliable indication of flow in the valve discharge pipe.

This requirement shall be met before fuel loading. (See NUREG-0578, Section 2.1.3a, and letters of September 27 and November 9, 1979.)

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 (SV) connected to the top of the pressurizer are employed to provide overpressure protection for the reactor coolant system at Farley Unit 2. Positive PORV position indication is obtained by stem-mounted limit switches which control indicating lights mounted on the main control board. The limit switches are mounted to sense the fully open and fully closed valve stem position. Limit switches are post-accident environment qualified and seismic excitation qualified switches. An alarm has been added in the main control room to indicate when any PORV is not fully closed. This alarm is hardwired, i.e., alarm operability is not dependent on the plant computer. The indicators, one set of red and green lights per PORV, are powered from the Class IE dc distribution system. The PORVs are air operated employing a solenoid to control instrument air. The PORV solenoid is powered from the same IE bus as the corresponding valve position indication. Control and indication of a PORV will be lost in the event that the bus is lost. The PORV is designed to fail closed on loss of power to the control solenoid. This configuration is considered acceptable.

Stem-mounted limit switches also are mounted on each safety valve stem to provide open and closed indication. These limit switches will control indicating lights mounted on the main control board (one red and one green light per SV as provided for each PORV). Indicator power is taken from a Class IE dc bus. The switches and associated electrical hardware are post-accident environment qualified and seismic excitation qualified. As for the PORV, an alarm is in the main control room to indicate when any safety valve is not fully closed.

PORV and SV position indicators are single-channel systems. As backup indication, there exist temperature detectors on all relief and safety valve tail pieces which join a common header and piping run to the pressurizer relief tank. Temperature, pressure, and level indication for the pressurizer relief tank are provided on the main control board and alarmed utilizing the plant computer.

Based on the applicant's submittals describing the system and discussion with the applicant's staff representatives, the position indication system described above is considered acceptable. The Office of Inspection and Enforcement will inspect for compliance prior to fuel loading.

II.E.1.2 Auxiliary Feedwater Initiation and Indication

Requirement

Install a control-grade system for automatic initiation of the auxiliary feedwater system that meets the single-failure criterion, is testable, and is powered from the emergency buses, and control-grade indication of auxiliary feedwater flow to each steam generator that is powered from emergency buses.

This requirement shall be met before fuel loading. (See NUREG-0578, Section 2.1.7a and b, and letters of September 27 and November 9, 1979.)

Position

To improve the reliability of the auxiliary feedwater system (AFWS), the staff is requiring licensees to upgrade the system where necessary to ensure timely automatic initiation when required. The system upgrade was to proceed in two phases. In the short term, as a minimum, control-grade signals and circuits are to be used to automatically initiate the AFWS. This control-grade system is required to meet the following requirements from NUREG-0578, Section 2.1.7.a

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 ac motor-driven pumps and valves in the auxiliary feedwater system shall be included in the automatic actuation (simultaneous and/or sequential) of the loads to 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 AFWS from the control room.

In the long term, these signals and circuits are to be upgraded in accordance with safety-grade requirements. Specifically, in addition to the above requirements, the automatic initiation signals and circuits must have independent channels, use qualified components, have system bypassed/inoperable status features, and conform to control system interaction criteria, as stipulated in IEEE Standard 279.

In addition to the above automatic initiation requirements, the capability to ascertain the actual performance of the AFWS from the control room must be provided. For Westinghouse plants, this is accomplished by a combination of auxiliary feedwater flow indication and steam generator wide range level indication in the control room.

In the short term, the AFWS flow and steam generator level indication is to meet control-grade requirements. Specifically, these flow and level instrument channels must be powered from the vital instrument buses, testability of these channels must be a feature of the design, and the instrumentation indicating the performance of the AFWS (flow and wide range level indication for each steam generator) must satisfy the single-failure criterion. For the long term, to adequately determine the performance of the AFWS, sufficient safety-grade instrumentation (specifically steam generator wide range level) must be provided.

Discussion

The auxiliary feedwater system at Farley Unit 2 is a part of the engineered safety features (ESF) and is identical to that of Unit 1. This system consists of two motor-driven pumps and one turbine-driven pump. The motor-driven pumps start automatically on low-low water level signals from two out of three level transmitters on any one steam generator, tripping of both steam generator feed pumps, any condition which causes a safety injection signal, or loss of offsite power (blackout signal). Operation of the turbine-driven auxiliary feedwater pump is automatically initiated by the opening of the steam supply valves to the turbine drive on either low-low water level signals from two of the three level transmitters on any two out of the three steam generators or a loss of power signal (two out of three reactor coolant pump bus undervoltage).

The automatic initiation signals and circuits for the AFWS at Farley Unit 2 comply with the single-failure criterion of IEEE Standard 279. Both the turbine- and motor-driven AFW pumps are tested monthly by manual initiation from the control room. Channel functional tests for the AFWS automatic initiation circuitry for steam generator low-low level, reactor coolant pump bus undervoltage, and safety injection are performed monthly. The auxiliary feedwater pumps are demonstrated to be operable at least once per 18 months by verifying that each pump starts automatically upon receipt of each auxiliary feedwater actuation test signal (including blackout signal) which simulates emergency operation of the system.

The automatic initiation signals and associated circuitry used to actuate the auxiliary feedwater system are part of the engineered safety features actuation system and are powered from the emergency buses. The channels which provide these signals are physically separated and electrically independent from the sensor through to the devices actuating the protective function. The ac motor driven pumps and valves in the AFWS at the Farley plant are powered from the emergency buses and are included in the automatic sequencing of loads onto these buses.

No single failure within the manual or automatic initiation systems for the auxiliary feedwater system at Farley Unit 2, will prevent initiation of the system by manual or automatic means. The AFWS can be operated manually locally from the hot shutdown panel or remotely from the control room.

There are six air (solenoid) operated flow control valves in the AFWS flow paths (one valve in each of the two AFW lines per steam generator), all of which are powered from the same train A battery. Typically during power operation, these valves will be closed, with the solenoids continuously energized. These valves open on an emergency signal and are designed to "fail safe" (fail open) upon loss of power or loss of air.

The applicant has not provided his design basis criteria for powering all the AFWS control valves from a single power source. The staff believes that this design may violate the single failure criterion of General Design Criterion 44, "Cooling Water." This criterion requires the system to have redundant power sources for the redundant AFW valves or that the system design be acceptable on some other basis. Staff is concerned that this arrangement may be susceptible to power source perturbations which could preclude these valves from performing their safety functions, thereby negating the availability of the AFWS. We discussed this concern with the applicant.

By letter dated August 1, 1980, applicant has stated that prior to exceeding zero power (physics testing) it will modify the power supply to provide train separation for the auxiliary feedwater flow control valve Solenoid valves. Staff believes that this approach will resolve the concern with regard to the single failure criterion referred to above. We require that a description of the design be submitted for our review prior to installation.

For any operational mode which required the auxiliary feedwater system to be operable, the status of the AFWS (light indication for train A and B) is given on the "safeguards features panel" in the control room. Whenever The AFWS is not operable, this places the Farley plant in a limiting condition of operation (LCO).

No modifications have been proposed which would result in interaction of the AFWS safety function with control functions.

The applicant has stated that the instrumentation and control required for the mitigation of the effects of accidents are designed and fabricated so that they will perform their safety functions after long term exposure to normal environmental conditions followed by exposure to post-LOCA environmental conditions. The environmental qualification of all safety related systems, including the AFWS, is being reviewed by the Equipment Qualification Branch as part of their review of conformance to NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment."

Capability to ascertain the performance of the AFWS at the Farley plant, Unit 2, is provided by flow indication (one flow indicating channel per steam generator) and steam generator level indication (one wide range and three narrow range level channels per steam generator) in the control room on the main control board. The auxiliary feedwater flow instrumentation channels receive their power from the class 1E vital instrument buses. The flow indicators on the main control board are powered from the plant emergency power. The applicant has indicated that the flow transmitters are seismically and environmentally qualified. At present, the auxiliary feedwater line flow indicators are not qualified; however, the licensee has commmitted to seismically and environmentally qualify these indicators by January 1, 1981. Testing of the AFW flow indication will be performed on 18-month intervals by injection of a test signal at the primary sensor. The instruments are calibrated if the output signals do not meet the required accuracy for the instrument.

A second indication of auxiliary feedwater system performance is provided by one safety-grade wide range level channel per steam generator. These wide range level channels are also tested at 18-month intervals per the Farley Nuclear Plant Technical Specifications. This combination of flow indication and steam generator wide range level indication (one flow and level channel per steam generator) satisfies the short-term control-grade single-failure criterion requirements.

Conclusion

Based on our review of the Farley Unit 2 auxiliary feedwater automatic initiation system, we conclude that the initiation signals, logic, and associated circuitry comply with the control grade (and long-term safety-grade requirements) of NUREG-0578, Section 2.1.7.a and the subsequent clarification issued by the staff, with the exception of the power source for the six air (solenoid)-operated flow control valves. An acceptable design of the power source for these valves will be installed prior to start of low-power testing. Our review of this modified design will be provided in a safety evaluation prior to low-power testing.

Our review of the AFWS flow and steam generator level indication at the Farley Unit 2 plant has concluded that this arrangement satisfies the short-term control-grade requirements and therefore is acceptable.

Our review of the conformance of the AFWS flow and steam generator level indication to the long-term safety-grade requirements will be provided in a subsequent SER supplement.

II.E.4.1 Containment-Dedicated Penetrations

Requirement

Provide a design of the containment isolation system for external recombiners or purge systems for post-accident combustible gas control, if used, that is dedicated to that service only and meets the single-failure criterion.

Review and revise, if necessary, the procedures for use of combustible gas control system following an accident resulting in a degraded core and release of radioactivity into the containment.

This requirement shall be met before fuel loading. (See NUREG-0578, Sections 2.1.5a and 2.1.5c, and letters of September 27 and November 9, 1979.)

Discussion and Conclusions

Hydrogen recombiners are included as a design basis for the Joseph M. Farley Nuclear Station, Unit 2. Redundant Westinghouse thermal recombiners in the containment building are the primary means of post-accident combustible gas control. In addition, the post-accident venting system is provided as a backup system for the redundant hydrogen recombiners. It consists of a supply line through which pressurizing air may be admitted to the containment and an exhaust line through which hydrogen-bearing gases may be vented from the containment. The gases are filtered to limit radioactive discharges to the environment.

Since internal hydrogen recombiners are used at the Farley 2 plant, there is no need for a dedicated system for connecting external recombiners to the containment. We conclude that with the presence of internal hydrogen recombiners at the Farley 2 plant, the requirement for dedicated penetrations for external recombiners or a post-accident external purge system, is not applicable to the Farley plant.

II.F.1 Additional Accident Monitoring Instrumentation

Requirement

Provide procedures for estimating noble gas, radioiodine, and particulate release rates if the existing effluent instrumentation goes off the scale.

This requirement shall be met before fuel loading. (See NUREG-0578, Section 2.1.8b, and letters of September 27 and November 9, 1979.)

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 $10^5$ μCi/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 $10^5$ μCi/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 requirement 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 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. Monitor/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.

      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.

## 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.

ii. Calculational methods for converting instrument readings to release rates based on exhaust air flow and taking into consideration radionuclide spectrum distribution as 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 Farley 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

## TABLE 2.1.8.b.2

## HIGH RANGE EFFLUENT MONITOR

Noble gases only

Range (overlap with normal effluent instrument range):

| | | |
|---|---|---|
| - | Undiluted containment exhaust | $10^{+5}$ μCi/cc |
| - | Diluted (> 10:1) containment exhaust | $10^{+4}$ μci/cc |
| - | Mark I BWR reactor buidling exhaust | $10^{+4}$ μCi/cc |
| - | PWR secondary containment exhaust | $10^{+4}$ μCi/cc |
| - | Buildings with systems containing primary coolant or gases | $10^{+3}$ μCi/cc |
| - | Other buildings (e.g., radwaste) | $10^{+2}$ μCi/cc |

° Not redundant - one per normal release point

° Se' .ic - no

° Power - vital instrument bus

° Specifications - per Regulatory Guide 1.97 and ANSI N320-1979

° Display;* continuous and recording with readouts in the technical support center (TSC) and emergency operations center (EOC)

Qualifications - no

*Although not a present requirement, it is likely that this information may have to be transmitted to the NRC. Consequently, consideration should be given to this possible future requirement when designing the display interfaces.

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 accidents. 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 Farley, Unit No. 2, consist of the plant vent stack, the main condenser air ejector to the turbine building vent stack, and the atmospheric steam relief discharge pipes.

As an interim measure for the determination of high level noble gas releases, Farley, Unit No. 2, will use an ion-chamber mounted a known distance perpendicular to the plant vent stack sampling line to measure radiation produced during passage of noble gas radionuclides during accidents. Portable gamma survey instruments will be used at a contact location on the air ejector discharge line in the event of offscale readings by the normal monitor and on the steam lines in the event of steam relief during accidents. The relationship between noble gas concentrations, measured radiation and release rates are predetermined by procedures. The applicant's summary of the interim procedures has been reviewed and was found to be acceptable.

Interim procedures for monitoring high level radioiodine and radioactive particulates in gaseous effluents have been developed. The applicant's summary of the interim procedures has been reviewed and was found to be acceptable.

The equipment and procedures described by the applicant meet our requirement and are, therefore, acceptable for fuel loading and low-power testing.

II.F.2 Inadequate Core Cooling Instruments

Requirement

Develop procedures to be used by operators to recognize inadequate core cooling with currently installed instrumentation in PWRs. Install a primary coolant saturation meter. Provide a description of any additional instruments or controls needed to supplement installed equipment to provide unambiguous, easy-to-interpret indication of inadequate core cooling, procedures for use of this equipment, analyses used to develop these procedures, and a schedule for installing this equipment.

This requirement shall be met before fuel loading. (See NUREG-0578, Section 2.1.3b, and letters of September 27 and November 9, 1979.)

Positions

General Design Criterion 13, "Instrumentation and Control," of Appendix A to 10 CFR Part 50, requires instrumentation to monitor variables "...for accident conditions as appropriate to assure adequate safety." In the past, GDC 13 was not interpreted to require instrumentation to directly monitor water level in the reactor vessel as an indicator of the adequacy of core cooling. The instrumentation available on some operating reactors that could indicate inadequate core cooling was generally included in the reactor design to perform other functions.

During the TMI-2 accident, a condition of low water level in the reactor vessel and inadequate core cooling existed and was not recognized for a long period of time. This problem was the result of a combination of factors including an insufficient range of existing instrumentation, inadequate emergency procedures, inadequate operator training, unfavorable instrument location (scattered information), and perhaps insufficient instrumentation.

The purpose of this review of the TMI-2 short-term recommendations is to evaluate the implementation of the post-TMI ICC indication requirements described in NUREG-0578 as follows:

1. 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 it not to be used exclusive of other related plant parameters.

2. 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 of the Position for Existing Instrumentation

1. The analysis and procedures addressed in paragraph one above will be reviewed and should be submitted to the NRC 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 thermocouples) 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 following Table II.F.2-1 provides a definition of information required on the subcooling meter. (Note: Table II.F.2-1, completed by applicant, provides the required information.)

Discussion of Existing Instrumentation

Description of Subcooling Monitor

The subcooling meter provides continuous main control board indication of margin-to-saturation conditions. The applicant will install a primary coolant saturation meter prior to fuel load. A summary of information required for the subcooling monitor was provided in Table II.F.2-1. This system has temperature inputs from resistance temperature detectors (RTDs) (2 hot and 2 cold legs per channel), in-core thermocouples (8 per channel), and temperature reference for the in-core thermocouples. Pressure inputs are taken from both the reactor coolant system and the pressurizer. A redundant subcooling meter display consists of two analog and digital meters mounted on the main control board. The Farley Unit 2 will use the dedicated digital calculator to calculate margin to saturation using input from the lowest pressurizer pressure and the highest of hot leg RTD temperature measurement or core exit thermocouples. The current main control board readout is pressure saturation. Emergency procedures describe the utilization of the subcooling monitor and appended portions of the steam tables to determine subcooling conditions in degrees Fahrenheit.

Alabama Power Company is pursuing with Westinghouse Electric Corporation a minor change to provide main control board readout in degrees Fahrenheit. A description of the modification required to implement this change will be presented to the NRC prior to its completion.

TABLE II.F.2-1

INFORMATION REQUIRED FOR THE SUBCOOLING MONITOR

DISPLAY

| | |
|---|---|
| 1. Information displayed | P - Psat subcooled<br>T - Tsat superheat |
| 2. Display type | Analog and Digital |
| 3. Continuous or on demand | Analog - continuous<br>Digital - on demand |
| 4. Single or redundant display | Redundant |
| 5. Location of display | Meter - main control board<br>Microprocessor - main control room instrument racks |
| 6. Alarms (include setpoints) | Caution: 25°F subcooled for RTD<br>15°F subcooled for T/C<br>Alarm: 0°F subcooled for RTD and T/C |
| 7. Overall uncertainty | Digital - 4°F for T/C; 3°F for RTD<br>Analog - 5°F for T/C; 5°F for RTD |
| 8. Range of display | Calibrated region - 1000 psi subcooled to 2000°F superheat overall; never offscale |
| 9. Qualifications | None at present |

CALCULATOR

| | |
|---|---|
| 1. Type | Dedicated digital |
| 2. If process computer is used, specify availability | N/A |
| 3. Single or redundant calculators | Redundant |
| 4. Selected logic | Highest Temperature for RTD or T/C and lowest pressure |
| 5. Qualifications | None at present |
| 6. Calculational technique | Functional fit - ambient to critical point |

INPUT

| | |
|---|---|
| 1. Temperature (RTDs or T/Cs) | RTD, T/C, and $T_{ref}$ |
| 2. Temperature (number and location of sensors) | RTD - 2 hot and 2 cold legs per channel<br>8 in-core T/C per channel |
| 3. Range of temperature sensors | RTD - 0-700°F<br>T/C - 0-1650°F (calibration unit range 0-2300°F) |
| 4. Uncertainty of temperature sensors | ±0.7% RTD |
| 5. Qualifications | IEEE 323 1971 |

TABLE II.F.2-1 (Continued)

| | |
|---|---|
| 6. Pressure (specify instrument used) | RCS Wide Range Pressurizer |
| 7. Pressure (number and location of sensors) | 2 wide range - Loops 1 and 3<br>1 narrow range - Pressurizer<br>(per channel) |
| 8. Range of pressure sensors | Wide range - 0-3000 psi<br>Narrow range - 1700-2500 psi |
| 9. Uncertainty of pressure | Wide range - ±1%<br>Narrow range - ±1.5%<br>Pressurizer - ±1.0% |
| 10. Qualifications | IEEE 323 1971 |

BACKUP CAPABILITY

| | |
|---|---|
| 1. Availability of temperature and pressure | Temp - Swap between T/C and RTD<br>Press - Can defeat any of the three inputs. System uses autioneered low pressure. |
| 2. Availability of steam tables | Saturated steam tables and tables to verify required sub-cooled conditions are included in Emergency Procedures. |
| 3. Training and operators | Operators have been trained on the use of the subcooling monitor to determine required subcooling conditions. |
| 4. Procedures | Emergency procedures have been revised to describe the utilization of the subcore cooling monitor readout and appended portions of the steam tables to determine subcooling conditions. A system operating procedure has been written to guide operators in the operation of the subcooling monitor. Appropriate personnel have been trained in these procedures. |

The Office of Inspection and Enforcement will verify that the subcooling monitor is installed and operational prior to fuel loading.

Description of In-Core Thermocouple Monitoring

A description of the in-core thermocouple measurement system was provided by the applicant in transmittals dated July 17 and July 24, 1980. The primary means of monitoring in-core thermocouple temperature is the core subcooling monitor system. Each channel of the subcooling monitor receives inputs from 8 thermocouples (2 per core quadrant per channel, for a total of 16 thermocouples). A digital readout of any of the 16 single thermocouple temperatures may be obtained at the subcooling monitor panel located behind the control board. The upper limit of the readout is in excess of 2300°F.

The second means available for monitoring thermocouple temperature is the in-core thermocouple readout panel located adjacent to the safeguards section of the main control board (MCB). Any of the 51 in-core thermocouples may be selected by toggle switch positioning and read on an analog readout. The readout range is 100-700 degrees Fahrenheit. If the readout should go off-scale high, thermocouple temperatures may be measured directly by connecting a "Digimite" or millivolt potentiometer to the thermocouple inputs at the readout panel.

A third means available for monitoring thermocouple temperature is the plant process computer. The computer constantly monitors all 51 in-core thermocouple temperature values. When any value exceeds preset alarm limits (700 degrees Fahrenheit hi, 1200 degrees Fahrenheit hi-hi)* the computer prints an alarm message on the alarm typewriter and on the control room cathode ray tubes (CRTs). Up to 51 of the thermocouples can be trended by the computer with output on the trend typewriter. Up to 26 thermocouple values may be selected for display on either control room CRT. The computer also is capable of determining and displaying the highest thermocouple value on the CRT. The trend typewriter, alarm typewriter and one CRT are located in the "at the controls" area in front of the safeguards panel of the MCB. The second CRT is installed on the center section (reactor panel) of the MCB. Trend and display selections are controlled from the computer operators console, located between the trend typewriter and alarm typewriter. The maximum computer thermocouple display range is 1900 degrees Fahrenheit. The time to print out all 51 thermocouple readings on the trend typewriter is about 4 minutes.

In the event that the margin to saturation decreases to less than 15 degrees Fahrenheit as indicated by thermocouple input to the subcooling monitor, the "core subcooling alarm" annunciator actuates and monitoring of the in-core thermocouples is initiated in accordance with Farley Nuclear Plant (FNP) Annunciator Response Procedures.

If any 5 exit in-core thermocouples indicate a temperature greater than or equal to 1200 degrees Fahrenheit, action is initiated in accordance with FNP-2-EOP-16.0, "Inadequate Core Cooling Due to a Small Loss of Coolant Accident," an FNP emergency operating procedure.

*"hi" is an abbreviation of "high" used by instrumentation technicians to designate a trip point on an instrument; "hi-hi" is the next trip point above the "hi" trip point.

Conclusions Regarding Existing Instrumentation

The Westinghouse Owners Group, of which Alabama Power Company is a member, has performed analyses as required by TMI Task I.C.1 to study the effects of inadequate core cooling. These analyses were provided to the NRC "Bulletins and Orders Task Force" for review on October 31, 1979. As part of the submittal made by the Owners Group, an "Instruction to Restore Core Cooling during a Small LOCA" was included. This instruction provides the basis for procedure changes and operator training required to recognize the existence of inadequate core cooling and restore core cooling based on existing instrumentation. Alabama Power Company has incorporated the key considerations of this instruction into the Unit 2 operator training program.

The emergency operating procedure FNP-2-EOP-16.0 entitled "Inadequate Core Cooling due to a Small LOCA" was reviewed and found to be generally consistent with the Westinghouse guideline. The Farley 2 procedure indicates that core exit thermocouple readings are to be taken from the core subcooling monitor panel. The applicant has agreed to revise his procedure to indicate that readings from either the process computer (which reports values up to 1900 degrees Fahrenheit) or from the core subcooling monitor panel (with readout capability up to 2300 degrees Fahrenheit) should be used. The staff has concluded that the current procedure FNP-2-EOP-16.0 is adequate to support operation up to 5 percent power for training during low power testing. However, procedure revisions as described in this paragraph are to be accomplished prior to a full power license. (See Item I.C.1 of Section 22.2 of this supplement).

The staff has reviewed the design of the core subcooling meter and in-core thermocouple systems, including display capabilities and the testing program for these systems. We have received a commitment from Alabama Power Company to perform an evaluation of the core subcooling monitor instrumentation capability to meet the requirements of Regulatory Guide 1.97, Revision 2, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environ Conditions During and Following An Accident," prior to full power operation. A report will be provided prior to full power operation giving the results of this evaluation and actions to be taken. We will require that a like evaluation of the in-core thermocouple system be included in this report prior to full power operation.

It is the staff position that the inadequate core cooling instrumentation system, including computers if applicable, should meet the requirements of Regulatory Guide 1.97, Rev. 2, Table I, Instrument Category I in the long term. Any deviation from Regulatory Guide 1.97 must be adequately justified.

The staff concludes that the procedures and instrumentation proposed by the applicant for detection of inadequate core cooling are acceptable for fuel load and low power operation up to 5 percent power.

Prior to full power operation, we will require:

(1) An acceptable evaluation report, including proposed actions, on the conformance of the final instrumentation to Regulatory Guide 1.97, Rev. 2.

(2) A description of the computer functions associated with inadequate core cooling monitoring and functional specifications for relevant software in the process computer and in the subcooling meter calculators. The reliability of the process computer must be addressed.

(3) An updated description and status report on the planned modification for subcooling meter displays.

(4) A revised procedure FNP-2-EOP-16.0 to use the process computer or in-core themocouple readout panel for operator actions.

Clarification of the Position for Additional Instrumentation

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. Applicants should provide the necessary design analysis for the selected instrumentation and should study advantages of various instruments to monitor water level and to monitor other parameters indicative of inadequate core cooling.

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 boiloff); and

    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.

7. All instrumentation in the final indequate core cooling monitoring system must be evaluated for conformance to Regulatory Guide 1.97, Revision 2, "Instrumentation for Light-Water-Cooled Nuclear Plants to Assess Plant Conditions During and Following An Accident," which is under development.

Discussion and Conclusions for Additional Instrumentation

Alabama Power Company, in their February 21, 1980 response to TMI Action Plan Item II.F.2, discussed several means of determining the approach to or existence of inadequate core cooling and concluded that measurement of reactor vessel water level is the most promising of the items discussed. They provided a conceptual design description of a basic delta pressure measurement system as their proposed selection for Farley 2.

The applicant, in a later submittal dated June 20, 1980, "Response to the TMI Action Plan," withdrew their description of the delta pressure measurement system as their selected method. They did not commit to installation of a particular system on the basis that all systems were under research and development.

After discussions with the staff, the applicant submitted a letter dated July 17, 1980, which provided new commitments with respect to their vessel water level system. Prior to receipt of a full power license, they agreed to provide:

1. A commitment to install a level system (a system other than differential pressure may be selected).

2. An installation schedule for the level system.

3. A testing schedule for the level system.

4. A commitment to provide contingency plans, possibly including alternative equipment, if the level system cannot be shown to properly relate to inadequate core cooling.

5. A commitment to address the present operability requirement date of January 1, 1981.

The staff, in further discussions with Alabama Power Company, indicated that a description of a proposed system and schedule for final selection and installation, including contingencies, was still needed prior to fuel load.

By letter dated August 6, 1980, the applicant provided the requested information. The applicant has selected a reactor vessel level measurement as an additional instrument to indicate inadequate core cooling. The applicant described its schedule for installing a level measurement system using $^{10}BF_3$ neutron detectors mounted externally to the reactor. Alabama Power Company is planning to install a test system in Farley Unit 1 in October 1980, during a refueling outage. Water level measurement tests will be made on Unit 1 during forced outages, if any, and during the next refueling outage of Unit 1, planned for late 1981. Design and analysis of the system will be made concurrently with Unit 1 tests. The final system, modified by test experience, will be installed in Farley 2 during the first refueling outage in mid-1982. If the boron neutron detector system is determined to be unacceptable based on Unit 1 tests, Alabama Power Company has committed to install an acceptable alternate system.

We conclude that the description of the vessel level measurement system and the schedule for its installation provided by applicant's August 5, 1980 letter meets our requirement for fuel loading and low-power testing. Our evaluation of applicant's schedule for development and installation is provided in Section 22.5 of this supplement.

II.G Emergency Power for Pressurizer Equipment

Requirement

Motive and control components of the power-operated relief valves and associated block valves and the pressurizer level indication shall be capable of being supplied from the offsite power source or from the emergency power buses when offsite power is not available.

This requirement shall be met before fuel loading. (See NUREG-0578, Section 2.1.1, and letters of September 27 and November 9, 1979.)

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 Conclusions

The two power-operated relief valves (PORVs) are pneumatically operated from the instrument air system upon actuation of solenoid control valves which are energized from redundant 125 volt dc buses. Instrument air is supplied by station air compressors which can be connected to the emergency power source in the event of loss of offsite power. A backup instrument air system for operating the PORVs is presently in the design stage.

The block valves for the PORVs are motor operated valves energized from redundant emergency 600 volt buses which are powered from their respective diesel generators automatically upon loss of offsite power. The PORVs and their associated block valves are each connected to the emergency source of power through a safety-grade circuit breaker.

Three level transmitter instrument channels indicate pressurizer level in the control room. These level instrument channels are independently powered from their vital 125-volt ac instrument buses through inverters which are fed from redundant 125-volt plant batteries.

We conclude that the licensee has satisfied the requirement for emergency power supply for the pressurizer PORVs, block valves, and level indicators.

II.K.1 IE Bulletins on Measures to Mitigate Small-Break LOCAs and Loss of Feedwater Accidents

The following requirements shall be met before fuel loading.*

C.1.5 Requirement

Review all valve positions, positioning requirements, positive controls and related test and maintenance procedures to assure proper engineered safety feature (ESF) functioning. (See Bulletin 79-06A, Item 8, 79-06B, Item 7, 79-08, Item 6.)

Discussion and Conclusion

The Alabama Power Company (APCo) response to this requirement indicates that all safety-related valve positions, positioning requirements, positive controls, and tests and maintenance procedures are specified in written Unit and System Operating Procedures, and in Surveillance Test Procedures which are verified by sign-off as part of the procedures.

*Table C.1 of NUREG-0660 lists all the requirements given in IE Bulletins.

Surveillance tests of engineered safety feature systems are scheduled at intervals established by Plant Administrative Procedures and Technical Specifications. Valve position and flow path verification checks are performed following major outages, significant maintenance in areas of safety-related equipment, or prior to returning a safeguards system to service from maintenance or off-normal operation as a plant operating policy which is incorporated into the Plant Administrative Procedures. APCo's procedures covering review and verification of the operational status of ESF-related valving adequately address the concerns raised in this item.

C.1.10 Requirement

Review and modify, as required, procedures for removing safety-related systems from service (and restoring to service) to assure operability status is known. (See Bulletin 79-05A, Item 10, 79-06A, Item 10, 79-06B, Item 9, 79-08, Item 8.)

Discussion and Conclusion

Administrative Procedures (AP-52 and AP-16) developed by APCo for Farley, Unit 2 were reviewed and revised to ensure that the operability of redundant safety-related systems be verified prior to removal of a safety-related system from service by redundant system activation, testing, and inspection before being placed in service. Existing requirements for verifying the operability of safety-related systems before return to service were also reviewed. These procedures have been incorporated into the operator training program.

An additional revision to the procedures requires that the Plant Operator-at-the-Controls log removal and return to service of all safety-related systems and equipment. Explicit notification of the Operator-at-the-Controls by the Shift Foreman is required by this revision whenever a safety-related system is removed from service, found to be inoperable, or returned to service. Notification of out-of-service safety-related systems between shift turnovers and relief is also provided by these revisions.

The review and revisions made to APCo's Administrative Procedures for Farley Unit 2 provide an adequate response to the safety concerns presented in this item.

C.1.17 Requirement

For Westinghouse-designed reactors, trip the pressurizer low-level coincident signal bistables, so that safety injection would be initiated when the pressurizer low-pressure setpoint is reached regardless of the pressurizer level. (See Bulletin 79-06A and Revision 1, Item 3.)

Discussion and Conclusion

Automatic initiation of safety injection on coincident low pressurizer pressure and level has been removed by a design change and a revised Technical Specification. These changes replace the pressure and level coincidence signal with a low pressurizer pressure signal.

These changes fulfill the requirement for this item.

II.K.3 Final Recommendations of B&O Task Force

The following requirements shall be met before fuel loading.*

C.3.9 Requirement

For Westinghouse-designed reactors, modify the pressure integral derivative controller, if installed on the power-operated relief valve (PORV), to eliminate spurious openings of the PORV.

Discussion and Conclusion

The applicant, upon the recommendation of Westinghouse, has modified the Farley Unit 2 design by incorporating "Rate-Time Constant" in the PID Controller of zero seconds. This, in effect, removes the derivative action from the controller which decreases the likelihood of opening the PORV since the actuation (opening) signal will not be sensitive to the rate of change of the pressurizer pressure.

We find that the applicant has satisfied this requirement for the elimination of spurious openings of the PORV caused by the derivative feature of the PID Controller.

C.3.10 Requirement

For Westinghouse-designed reactors, if the anticipatory reactor trip upon turbine trip is modified so that it will be bypassed at power levels less than 50 percent, rather than below 10 percent as in current designs, demonstrate that the probability of a small-break LOCA resulting from a stuck-open PORV is not significantly changed by this modification.

Discussion and Conclusion

The licensing basis for Farley Nuclear Plant includes an anticipatory reactor trip upon turbine trip which has been modified to be bypassed at power levels of 50 percent or less. The Westinghouse design criterion is that load rejections up to 50 percent should not require a reactor trip if all other functions operate properly. The power mismatch is accommodated by steam dump (40 percent) and automatic control rod insertion (10 percent).

Analytical studies performed by Westinghouse for the two Farley units (WCAP-8318, Section 7.3) have shown that primary sytem pressure increases of less than 100 pounds per square inch are predicted for 50 percent step load rejections form rated full pwoer and from 75 percent power. Pressure increases less than 100 pounds per square inch would not open the PORV. From these results, it can be reasonably estimated that a 50 percent load rejection from operation at 50 percent power would produce similar pressure transients; however, analyses of such an incident was not included in the studies.

*Table C.3 of NUREG-0660 lists all the requirements derived from final recommendations of the B&O Task Force.

The applicant has indicated in a meeting with the staff that the load rejection transient from 50 percent power will be analyzed and that test data exists which would serve to support the analytical predictions. This data will be furnished by September 15, 1980. Review of this information and data will be required to reach a conclusion on the acceptability of the anticipatory trip bypass below 50 percent power. We conclude that operation up to 5 percent of rated power is acceptable because the anticipatory trip is always bypassed for power levels below 10 percent of rated power. We will complete our review prior to operation above 5 percent of rated power.

C.3.11 Requirement

Demonstrate that the PORV installed in the plant has a failure rate equivalent to or less than the valves for which there is an operating history.

Discussion and Conclusion

The applicant has indicated that Farley Unit 2 has PORVs furnished by Westinghouse which are of the same type used in a majority of Westinghouse-designed plants, including Farley Unit 1.

Information furnished on operating Westinghouse-designed plants has shown that for 60 known cases of challenges to PORVs of the type used for the Farley units, no failure to reseat following the challenges was experienced. Section 3.2, Appendix VIII of NUREG-0611 further indicates that the summary prepared for the B&O Task Force was incomplete and further documentation was recommended and will be furnished in January 1981.

Based on this information, the failure rates to be expected for the Farley Unit 2 PORVs are in compliance with the requirements of this item.

C.3.12 Requirement

For Westinghouse-designed reactors, confirm that there is an anticipatory reactor trip on turbine trip.

Discussion and Conclusion

The Farley Unit 2 has an anticipatory reactor trip on turbine trip (see Requirement C.3.10 above). Therefore, we find that this requirement has been satisfied.

III.A.1.1 Upgrade Emergency Preparedness

Requirement

Comply with Appendix E, "Emergency Facilities," to 10 CFR Part 50, Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants," and for the offsite plans, meet essential elements of NUREG-75/111 or have a favorable finding from FEMA.

This requirement shall be met before fuel loading.

Discussion and Conclusions

We have reviewed the applicant's emergency plan for a fuel load and low power testing license. For this license, we require that the combined applicant, State, and local emergency plans must meet:

a. Current Regulatory Requirements at 10 CFR Part 50, Appendix E.

b. Regulatory Position Statements in Regulatory Guide 1.101 (March 1977).

c. Essential planning elements in NUREG 75/111 and Supplement 1 thereto or receive a favorable finding by FEMA.

We reviewed the combined applicant, State, and local emergency plans and find that they met the above criteria. The basis for this finding is summarized below.

The applicant submitted a plan for coping with emergencies at Joseph M. Farley Nuclear Plant, Units 1 and 2 (8-15-74; Rev. 1, 2-23-77). We reported that the applicant's emergency plan met the requirements of Appendix E to 10 CFR Part 50 and provided an adequate basis for an acceptable state of emergency preparedness.

The applicant's emergency plan includes provisions for coping with emergencies within the boundary and the environs of the plant site. Responsibility for planning and implementing all emergency measures within the site boundaries rests with the licensee. The planning and implementation of measures to cope with plant-related emergencies outside the site boundary are a coordinate effort involving the applicant and local, State and Federal agencies having emergency responsibilities. The emergency plan describes the coordination of the arrangements and agreements between the licensee and these agencies. Provisions have been made for an annual review of the emergency plan and for periodic testing, updating, and improving procedures based on training, drills, and exercises. The scope and content of the applicant's emergency plan is substantially equivalent to that recommended in Annex A, "Organization and Content of Emergency Plans for Nuclear Power Plants," to Regulatory Guide 1.101.

Based on review of the applicant's emergency plan, we conclude that it meets the regulatory position statements of Regulatory Guide 1.101.

The Alabama Radiation Emergency Response Plan (ARERP) updated February 16, 1978, was reviewed against the guideline standards of the Nuclear Regulatory Commission's "Guide and Checklist for Development and Evaluation of State and Local Government Radiological Emergency Response Plans 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's concurrence in a State plan. As a result of this review and in accordance with the provisions of the Federal Register Notice (Volume 40, No. 248, December 24, 1975), the NRC concurred formally in the ARERP on February 9, 1979.

Revisions to the State of Alabama and the State of Georgia Radiological Emergency Operations Plans are being submitted to FEMA for review. These draft plans were written to meet the essential requirements of NUREG-0654. By letter dated August 28, 1980, FEMA finds our recommendation for issuing a fuel loading and low power testing license to be reasonable (See Appendix D to this supplement).

As a result of the Commission's action plan for Promptly Upgrading Emergency Preparedness at Power Reactors (SECY 79-450), the Emergency Planning Review Team conducted a site visit and technical meeting with the applicant, State, and local officials. In response to our visit, the applicant submitted on December 28, 1979, a proposed revision (Rev. 2 and 3) to the Farley Nuclear Plant Emergency Plan. This proposed revised plan is currently under staff review and the results of this effort will be reported upon prior to granting a full power license; however, preliminary review reflects that the licensee has designated an interim Emergency Operations Facility, established an interim Technical Support Center, and established an onsite Operations Support Center (Joseph M. Farley Nuclear Plant Unit 2 "Response to the TMI-2 Action Plan," transmitted by applicant's letter dated June 20, 1980) which we find meets those additional items in the interim upgraded criteria necessary for the issuance of this fuel load license.

In summary, based on our review of the combined applicant, State and local emergency plans, we conclude that the current plan provides an acceptable state of emergency preparedness for a fuel load and low power license.

Deficiencies to be Corrected for a Full Power License

Current efforts by the staff, the Commission and FEMA to upgrade rules and guidance in the area of emergency planning should result in definitive and uniform acceptance criteria in the near future. The proposed revision to Appendix E to 10 CFR Part 50 will include required implementation schedules for applicants and licensees. In the meantime, the NRR staff has informed LWR applicants and licensees of its new requirements in the emergency planning area via various letters and orders. Highlights of these current staff requirements yet to be accommodated in the emergency plans for the applicant are:

1. Demonstration of preparedness to cope with a full spectrum of accidents as outlined in NUREG-0396.

2. Provisions of means to essentially complete notification of the public within 10 miles of the station in an expeditious fashion (i.e., within 15 minutes) in the event of a serious accident.

3. Establishment of permanent near-site Emergency Operations Facility, Technical Support Center, Onsite Operations Support Center, including all required appointments.

4. Adoption of the predetermined emergency detection/classification/notification immediate action scheme in NUREG-0610, and provision of corresponding emergency action levels.

5. Implementation of an acceptable public information program.

6. Provision of analyses of times required for evacuation of populations within 10 miles of the site with and without means for prompt warning of the people.

7. Improvement of the State and local emergency plans for the site considering upgraded joint NRC/FEMA criteria (NUREG-0654.)

III.A.1.2 Upgrade Emergency Support Facilities

Requirement

Establish an interim onsite technical support center separate from, but close to, the control room for engineering and management support of reactor operations during an accident. The center shall be large enough for the necessary utility personnel and five NRC personnel, have direct display or callup of plant parameters, and dedicated communications with the control room, the emergency operations center, and the NRC. Provide a description of the permanent technical support center.

Establish an onsite operational support center separate from, but with communications to, the control room for use by operations support personnel during an accident.

Designate a near-site emergency operations facility with communications with the plant to provide evaluation of radiation releases and coordination of all onsite and offsite activities during an accident.

These requirements shall be met before fuel loading. (See NUREG-0578, Sections 2.2.2.b, 2.2.c, and letters of September 27 and November 9, 1979 and April 25, 1980.)

Discussion and Conclusion

Our discussion and conclusion regarding this requirement is given in III.A.1.1 above. We conclude that the requirement to upgrade the emergency support facility has been met.

III.D.3.3 Inplant Radiation Monitoring

Requirement

Provide the equipment, training, and procedures necessary to accurately determine the presence of airborne radioiodine in areas within the plant where plant personnel may be present during an accident.

This requirement shall be met before fuel loading. (See NUREG-0578, Section 2.1.8c, and letters of September 27 and November 9, 1979.)

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 January 1, 1980 or fuel loading date, whichever is later. 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 $^{131}I$. A representative air sample shall be taken and then counted for $^{131}I$ 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. For Section 22.5, Dated Requirements, we require that 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 applicant has a portable monitoring system which uses an iodine silver zeolite sampler and single channel analyzer. Procedures for the use of this equipment are in effect. The necessary training has been provided. Thus the capability exists for accurately monitoring iodine in the presence of noble gases. The applicant can also purge these samples of entrapped noble gases by the use of nitrogen gas.

The applicant has stated that the samples will be counted in a low background counting facility. By letter dated July 24, 1980, the applicant stated that they will have two counting rooms (one per unit). In the event of an accident, the applicant estimates that the background radioactivity level in the non-affected unit's counting room will be low enough to perform the above measurements. However, if the background level is too high in the non-affected unit, the necessary measuring equipment will be relocated within one hour to the water treatment plant or to the emergency operation facility upon its completion.

The equipment, training, and procedures described by the applicant meet our dated requirement for accurately measuring radioiodine concentration (Section 22.5 of this supplement) as well as the requirement for determining its presence and are therefore acceptable.

## 22.3 Full-Power Requirements*

### II.E.3.1 Emergency Power For Pressurizer Heaters

Requirement

Install the capability to supply from emergency power buses a sufficient number of pressurizer heaters and associated controls to establish and maintain natural circulation in hot standby conditions.

This requirement shall be met before issuance of a full-power license. (See NUREG-0578, Section 2.1.1, and letters of September 27 and November 9, 1979.)

Discussion and Conclusion

The Westinghouse Owner's Group analysis determined that in order to establish and maintain natural circulation for a 3-loop plant with a 1400-cubic-foot pressurizer, a heater of 125kw capacity would be required to be placed in service within one hour.

For Farley Unit 2, two backup heater groups each rated at 270kw can be energized from separate 600-volt emergency power trains. These trains are energized from separate diesel generators upon loss of offsite power. The pressurizer heater groups are load-shed from the normal bus on loss of offsite power and are not loaded on emergency buses automatically. The continuous rating (2000 hours) of the diesel generator indicates that following automatic sequence loading of emergency loads there is insufficient D-G capacity to also allow automatic loading of the pressurizer heaters. However, this total load does not exceed the 2-hour D-G rating. Procedures are provided to instruct the operator in system load shedding and in the manual loading of the pressurizer heaters to establish and maintain natural circulation. The pressurizer heater groups are connected to the emergency 600-volt buses through safety-grade circuit breakers.

We conclude that the licensee has satisfied the requirements for pressurizer heaters.

### II.E.4.2 Containment Isolation Dependability

Requirement

Provide (1) containment isolation on diverse signals, such as containment pressure or ECCS actuation, (2) automatic isolation of nonessential systems (including the bases for specifying the nonessential systems), (3) no automatic reopening of containment isolation valves when the isolation signal is reset.

These requirements shall be met before issuance of a full-power license. See NUREG-0578, Section 2.1.4, and letters of September 27 and November 9, 1979.

*Part 2 of NUREG-0694 lists all the full power requirements. All remaining requirements will be addressed in Supplement 5 to the SER. This supplement addresses only those completed to date.

Discussion and Conclusion

The containment isolation system is designed to automatically isolate the containment atmosphere from the outside environment under accident conditions. Double barrier protection, in the form of closed systems and isolation valves, is provided to assure that no single active failure will result in the loss of containment integrity. There are two phases of containment isolation at the Farley 2 plant. Phase A isolates all penetrations except component cooling water, containment spray, and systems essential for safe shutdown. Phase B isolates all remaining process lines except safety injection, containment spray, service water lines to containment coolers, and auxiliary feedwater.

Our review of the containment isolation system includes verification that there is diversity of parameters sensed for the initiation of containment isolation, as called for by Standard Review Plan Section 6.2.4, "Containment Isolation System." The Farley 2 plant's containment isolation system design meets this requirement. The parameters sensed for the initiation of containment isolation include high containment pressure, high differential pressure between main steam lines, pressurizer low pressure coincident with low water level and low main steam line pressure. A high radiation signal is also used for purge system isolation. Furthermore, resetting of isolation signals will not automatically reopen isolation valves; manual action is needed to open each valve.

Since the Farley 2 plant meets all the requirements of II.E.4.2, we conclude the isolation dependability of containment is acceptable.

## 22.4 NRC Actions

### I.B.2.2 Reactor Inspector At Operating Reactors

Requirement

An NRC resident inspection will be assigned to each site.

This action shall be completed before fuel loading.

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 insepctor at near-term operating plants by June 1980.

Discussion and Conclusion

At NRC inspector with several years of nuclear plant operation and inspection experience was transferred to the Farley Nuclear Station as a resident inspector in December 1979. In March 1980 a second inspector, also possessing several years experience, was assigned as resident inspector. This inspector is currently in training. At the time of his assignment, the previously assigned inspector assumed the duties of senior resident inspector.

Placement of NRC resident inspectors at this facility has been accomplished.

### I.D.1 Control Room Design Review

Requirement

NRC review of applicant's preliminary assessment of the control room design to determine whether the assessment is adequate and identify any necessary corrections and approve the schedule for correction of the deficiencies.

This action shall be completed prior to fuel loading.

Discussion and Conclusion

The staff has completed its review. Discussion and conclusions are included under Requirement I.D.1, Section 22.2 of this supplement.

II.B.7 Analysis of Hydrogen Control

Requirement

Reach a decision on the immediate requirements, if any, for hydrogen control in small containments and apply, as appropriate, to new operating licenses pending completion of the degraded core rulemaking in II.B.8 of the Action Plan.

This action shall be completed before issuance of a full-power license.

Discussion and Conclusion

The staff action on item II.B.7 was completed with issuance of the Commission papers (SECY-80-107, -80-107A and -80-107B) which discussed the technical basis for: 1) the staff position on interim hydrogen control requirements (inerting) for small containments; and 2) continued operation and licensing of nuclear power plants pending the rulemaking proceeding. With regard to Farley 2, which is a dry type of containment, the staff position is that no additional hydrogen mitigation measures beyond the current design basis is needed pending the rulemaking proceeding.

II.B.8 Degraded Core - Rulemaking

Requirement

Issue an advance notice of rulemaking on requirements for design and other features for accidents involving severely damaged cores.

This action shall be completed before issuance of a full-power license.

Discussion and Conclusions

The accident at Three Mile Island, Unit 2 resulted in a severely damaged core accompanied by the generation and release to containment of hydrogen in excess of those amounts required to be considered in current regulations. This accident highlighted the difficulties associated with mitigating the consequences of an accident more severe than the current design basis accidents. As a consequence, the TMI Action Plan (NUREG-0660), at item II.B.8, calls for a rulemaking proceeding on consideration of degraded or melted cores in safety reviews to solicit comments.

The first steps in the resolution of item II.B.8 will be the issuance of an advance notice of rulemaking and the issuance of an Interim Rule. The advance notice has been drafted and is under staff review. The Interim Rule has also been prepared and is expected to be ready for Commission consideration in the near future. The Interim Rule, in summary, addresses the following areas:

1. Requires inerting of all BWR Mark I and Mark II containments;

2. Requires owners of all other plants to evaluate the effects of large amounts of hydrogen generation and to propose and assess mitigation techniques for control of hydrogen.

3. Codifies various lessons learned to reduce the likelihood of degraded core accidents.

In addition to the efforts related to the rulemaking, the staff has requested that a research program be initiated to investigate the effects of degraded/melted core accidents for generic LWR plant designs, and to investigate various safety systems to reduce the effects of such accidents. As a part of this safety research we have identified the evaluation of hydrogren control of ice condenser and BWR Mark III containments as a priority item. Additionally, the staff will seek assistance to evaluate the effectiveness of distributed ignition sources within containment on an expedited basis; i.e., within about 3 months. The use of ignitors within containment is currently regarded as the most promising short term hydrogen control device which could be adapted to current plant designs. The staff will, however, evaluate a spectrum of mitigation techniques to control hydrogen and reduce the impact of severely degraded core accidents as part of the safety research program discussed above.

III.A.3.1 Role of NRC in Emergency Preparedness

Requirement

More explicitly define the role of the NRC in emergency situations involving NRC licenses.

Conclusion

This action was completed in a meeting between the staff and the Commission on February 6, 1980.

III.A.3.3 Communications

Requirement

Install direct dedicated telephone lines between each plant and the NRC Operations Center.

This action shall be completed prior to fuel loading.

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

Direct dedicated telephones have been installed at the Farley Nuclear Station Units 1 and 2 control rooms, the NRC resident inspector's office, hot shutdown panel, and the site technical support center. A second network for health physics and environmental information has been installed with extensions in the control room, health physics supervisor's office, technical support center, and the conference room. A functional check of these phones was performed after installation. This task is completed.

III.B.2 Implementation of NRC and FEMA Responsibilities

Requirement

The applicant emergency plans shall meet the requirements of Appendix E to 10 CFR Part 50 and the positions in Regulatory Guide 1.101 (March 1977). Offsite plans shall meet the essential planning elements in NUREG-75/111 and Supplement 1 thereto or receive a favorable finding by FEMA.

This requirement shall be met prior to fuel loading.

Discussion and Conclusion

The discussion of this item is included in III.A.1.1 of Section 22.2 of this supplement. We conclude that the requirement of this item is met.

III.D.2.4 Offsite Dose Measurements

Requirement

The NRC will place approximately 50 thermoluminescent dosimeters (TLDs) around the site in coordination with the applicant and State environmental monitoring program.

This action shall be completed prior to issuance of a full-power license.

Position

The Office of Inspection and Enforcement (IE) will place 50 TLDs around each site in coordination with States and utilities. During normal operation, IE quarterly reports from these dosimeters will be provided to NRC, State, and Federal organizations. In the event of an accident, the dosimeters can be read at a frequency appropriate to the needs of the situation.

Discussion and Conclusions

The TLD monitoring network has been installed at Farley Nuclear Station since February 1980. The system consists of a series of concentric rings around the site at radiuses of 1-2 miles and 3-5 miles. Quarterly reports from these dosimeters will be provided to the licensee and the State.

IV.F.1 Power-Ascension Test

Requirement

IE will monitor the power-ascension test program to confirm that safety is not compromised because of the expanded startup test program and economic costs of the delay in commercial operation.

This action shall be taken during the startup and power-ascension test program.

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's power-ascension test program is defined by Section 14.0 and Table 14.1-2 of the Units 1 and 2, Final Safety Analysis Report. Portions of tests on all shifts will be witnessed by the resident inspectors, with assistance by IE Region II inspectors as necessary.

## 22.5 Dated Requirements

### I.A.1.1 Shift Technical Advisor

#### Requirement

The Shift Technical Advisor shall have a technical education, which is taught at the college level and is equivalent to about 60 semester hours in basic subjects of engineering and science, and specific training in the design, function, arrangement and operation of plant systems and in the expected response of the plant and instruments to normal operation, transients and accidents including multiple failures of equipment and operator errors.

This requirement shall be met by January 1, 1981. (See NUREG-0578, Section 2.2.1b, and letters of September 27 and November 9, 1979.)

#### Discussion and Conclusions

By letters dated June 20 and August 1, 1980, the applicant has stated that shift technical advisors will have received the additional training identified in this requirement by January 1, 1981. Science and engineering courses will include mathematics, chemistry, metallurgy, reactor physics, heat transfer, fluid mechanics and thermodynamics. Training will be provided in the response and analysis of the plant for various transients and accidents, including accidents in which the core may be severely damaged (Requirement II.B.4 in Section 22.2 of this supplement). Training will include instruction in plant design and layout and the capabilities of instruments and controls in the control room.

We conclude that the applicant has taken adequate measures to date toward meeting this requirement.

### I.A.2.1 Immediate Upgrading of Operator and Senior Operator Training and Qualification

#### Requirement

Applicants for SRO licenses shall have 4 years of responsible power plant experience, of which at least 2 years shall be nuclear power plant experience (including 6 months at the specific plant) and no more than 2 years shall be academic or related technical training.

Certifications that operator license applicants have learned to operate the controls shall be signed by the highest level of corporate management for plant operation.

These requirements shall be met on or after May 1, 1980. (See March 28, 1980 letter.)

Revise training programs to include training in heat transfer, fluid flow, thermodynamics, and plant transients.

This requirement shall be met by August 1, 1980. (See March 28, 1980 letter.)

Discussion and Conclusions

By letter dated August 1, 1980, the applicant stated it meets all the requirements of this item. In addition, we have reviewed applications for licenses for SRO and RO for the Farley Plant Unit 2. All SRO applicants meet the above experience requirements. Applications which have been recently submitted are signed by the Plant Manager, General Manager - Nuclear Generation, and the Vice President - Nuclear Generation. Changes to the training program which will satisfy the third requirement of this item were submitted to the NRC on August 8, 1980.

We conclude that Farley has satisfied the requirements of this item.

I.A.2.3 Administration of Training Programs for Licensed Operators

Requirement

Training instructors who teach systems, integrated responses, transient and simulator courses shall successfully complete an SRO examination.

Applications shall be submitted by August 1, 1980. (See March 28, 1980 letter.)

Instructors shall attend appropriate retraining programs that address, as a minimum, current operating history, problems and changes to procedures and administrative limitations. In the event an instructor is a licensed SRO, his retraining shall be the SRO requalification program.

Programs shall be initiated by May 1, 1980. (See March 28, 1980 letter.)

Discussion and Conclusions

By letter dated August 1, 1980, the applicant has responded to these requirements. Permanent plant instructors involved in training programs for licensed operators will be SRO-licensed or will make application for licenses. Instructors obtained from other sources will be SRO-licensed, will make applications for licenses, or will be SRO-cold-license-certified, or will make application for NRC Instructor certification; certification is expected to include satisfactory completion of an NRC senior operator examination and adherence to INPO standards. Instructors will attend license retraining programs. All licensed SRO instructors will attend the SRO requalification program.

We have reviewed the applicant's submittal and operating staff. There are currently five licensed SROs on the Farley Training Staff. All instructors and licensed SRO instructors will attend the requalification program. Based on the foregoing, we have concluded that the applicant has complied with our requirement in this item.

I.A.3.1 Revise Scope and Criteria for Licensing Exams

Requirement

Applicants for operator licenses will be required to grant permission to the NRC to inform their facility management regarding the results of examinations.

Contents of the licensed operator requalification program shall be modified to include instruction in heat transfer fluid flow, thermodynamics, and mitigation of accidents involving a degraded core.

These requirements shall be met by May 1, 1980. (See March 28, 1980 letter.)

The criteria for requiring a licensed individual to participate in accelerated requalification shall be modified to be consistent with the new passing grade for issuance of a license.

This requirement shall apply to all annual requalification examinations conducted after March 28, 1980. (See March 28, 1980 letter.)

Requalification programs shall be modified to require specific reactivity control manipulations. Normal control manipulations, such as plant or reactor startups, must be performed. Control manipulations during abnormal or emergency operations shall be walked through and evaluated by a member of the training staff. An appropriate simulator may be used to satisfy the requirements for control manipulations.

This requirement shall be met by August 1, 1980. (See March 28, 1980 letter.)

Discussion and Conclusions

By letter dated August 1, 1980, the applicant stated that it has met all the requirements of this item. We have reviewed this letter and also operator license applications, and the revised requalification program outline. The applicant included a statement on its license application, granting permission for the NRC to inform the Farley management regarding the results of examinations. In the letter of August 7, 1980, the applicant submitted its outline of the training in heat transfer, fluid flow, thermodynamics and mitigation of accidents for their requalification program. Also included was the revised examination criteria for accelerated training consistent with new passing grades for issuance of licenses. Modifications to the requalification program which revised specific reactivity control manipulations for startup, normal, abnormal and emergency operations have been submitted.

Based on the information submitted by Farley, we conclude that Farley has satisfied all requirements of this item.

I.C.1 Short-Term Accident Analysis and Procedure Revision

Requirement

Analyze the design basis transients and accidents including single active failures and considering additional equipment failures and operator errors to identify appropriate and inappropriate operator actions. Based on these analyses, revise, as necessary, emergency procedures and training.

This requirment was intended to be completed in early 1980; however, some difficulty in completing this requirement has been experienced. Clarification of the scope and revision of the schedule are being developed and will be issued by July 1980. It is expected that this requirement will be coupled with Task I.C.9., Long-term Upgrading of Procedures. (See NUREG-0578, Sections 2.1.3b and 2.1.9, and letters of September 27 and November 9, 1979.)

Discussion and Conclusion

Emergency procedures will be completed and incorporated into plant training programs prior to full power operation. For discussion see I.C.1 Section 22.2 of this Supplement.

II.B.1 Reactor Coolant System Vents

Requirement

Install reactor coolant system and reactor vessel head high-point vents that are remotely operable from the control room.

This requirement shall be met before January 1, 1981. See letters of September 27 and November 9, 1979.

Discussion and Conclusions

By letters dated June 20 and August 1, 1980, the applicant has described a system for venting the reactor vessel head. The system is operable from the control room. Applicant has committed to install the system by January 1, 1981, or prior to full power operation, whichever is later. The design was scheduled for completion August 8, 1980, and all material is scheduled for shipment by September 1, 1980.

We will review the results of the design prior to full power operation and report the conclusions of our review in a future supplement to the SER. We conclude that applicant has taken adequate steps to date toward meeting this requirement. We will pursue an acceptable schedule for installation after January 1, 1981, on a basis similar to that taken for the North Anna 2 and Sequoyah facilities.

II.B.2 Plant Shielding

Requirement

Complete modifications to assure adequate access to vital areas and protection of safety equipment following an accident resulting in a degraded core.

This requirement shall be met by January 1, 1981. (See NUREG-0578, Section 2.1.6b, and letters of September 27 and November 9, 1979.)

Discussion and Conclusions

By letters dated October 24, November 21, December 31, 1979, and January 21 and June 20, 1980, the applicant has provided a description of the shielding design review to be done. Applicant has committed to complete its review and make recessary shielding changes in the plant prior to full power operation or January 1, 1981, whichever is later.

We will review the results of the design and report our conclusions in a future supplement to the SER. We conclude that applicant has taken adequate steps to date toward meeting this requirement.

II.B.3 Post-Accident Sampling

Requirement

Complete corrective actions needed to provide the capability to promptly obtain and perform radioisotopic and chemical analysis of reactor coolant and containment atmosphere samples under degraded-core conditions without excessive exposure.

This requirement shall be met by January 1, 1981. (See NUREG-0578, Section 2.1.8a and letters of September 27 and November 9, 1979.)

Discussion and Conclusions

By letters dated June 20 and August 1, 1980, the applicant has provided a description of equipment and procedures to be used to sample reactor coolant and containment atmosphere following an accident in which there is core degradation. The applicant has indicated that the plant systems modifications to provide sampling capability under degraded core condition, will be completed by January 1, 1981. Based on preliminary review of the information provided by the applicant, we conclude that the applicant has taken adequate steps to date towards meeting this requirement.

Our conclusions based on a detailed review of the informaiton provided by the applicant, will be reported in a future supplement to the SER.

II.D.1 Relief and Safety Valve Test Requirements

Requirement

Complete tests to qualify the reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.

This requirement shall be met by July 1, 1981. (See NUREG-0578, Section 2.1.2 and letters of September 27 and November 9, 1979.)

Discussion and Conclusions

Our discussion of applicant's response to this requirement is provided in Section 22.2 of this supplement.

We conclude that the commitment provided by the applicant in its July 23, 1980 letter indicates that adequate steps are being taken to fulfill this requirement. The staff is currently preparing more definitive requirements to be sent to all applicants and licensees. We will report on applicant's response to our new requirements in a future supplement to this SER.

II.E.1.2 Auxiliary Feedwater Initiation and Indication

Requirement

Upgrade, as necessary, automatic initiation of the auxiliary feedwater system and indication of auxiliary feedwater flow to each steam generator to safety-grade quality.

This requirement shall be met by January 1, 1981. (See NUREG-0578, Sections 2.1.7a and b, and letters of Sptember 27, and November 9, 1979.)

Discussion and Conclusions

Our discussion of applicant's response to this requirement is given in Section 22.2 of this supplement. We concluded that the Farley Unit 2 auxiliary feedwater system meets this requirement, except for the power supply to six flow control valves. Applicant has commited to design and install a modified power supply to these valves that will meet the requirements prior to the start of low power testing. We will review the design prior to installation and report our conclusions in a future safety evaluation report supplement.

II.E.4.1 Containment Dedicated Penetration

Requirement

Install a containment isolation system for external recombiners or purge systems for post-accident combustible gas control, if used, that is dedicated to that service only and meets the single-failure criterion.

This requirement shall be met before January 1, 1981. See NUREG-0578, Section 2.1.5a and c and letters of September 27 and November 9, 1979.

Conclusion

As discussed in Section 22.2 of this supplement, Farley 2 uses internal electric recombiners. Therefore, the requirement for dedicated penetrations for external recombiners is not applicable.

II.F.1 Additional Accident Monitoring Instrumentation

Requirement

Install continuous indication in the control room of the following parameters:

a. Containment pressure from minus 5 psig to three times the design pressure of concrete containments and four times the design pressure of steel containments;

b. Containment water level in PWRs from (1) the bottom to the top of the containment sump, and (2) the bottom of the containment to a level equivalent to 600,000 gallons of water;

Containment water level in BWRs from the bottom to 5 feet above the normal water level of the suppression pool;

c. Containment atmosphere hydrogen concentration from 0 to 10 volume percent;

d. Containment radiation up to $10^8$ Rad/hr;

e. Noble gas effluent from each potential release point from normal concentrations to $10^5$ μCi/cc (Xe-133).

Provide capability to continuously sample and perform onsite analysis of the radionuclide and particulate effluent samples.

This instrumentation shall meet the qualification, redundancy, testability and other design requirements of the proposed revision to Regulatory Guide 1.97.

This requirement shall be met by January 1, 1981. See NUREG-0578, Section 2.1.8b, and letters of September 27 and November 9, 1979.

Discussion

By letter dated August 1, 1980, the applicant provided the status of design and schedule for procurement and installation of instruments identified in this requirement. Containment pressure measurement design is completed and installation is scheduled for January 1, 1981. Containment water level wide range instrument is installed; the narrow range instrument materials are scheduled to be shipped November 1, 1980 and to be installed January 1, 1981. The installed hydrogen monitoring equipment is stated to meet our requirements. A Victoreen 875 Detector System to measure containment radiation up to $10^7$ Rad/hour has been ordered and is scheduled to be installed by January 1, 1981. An Eberline SPING-4 sampler has been ordered to measure noble gas effluent; all equipment is scheduled to be shipped by October 15, 1980 and to be installed by January 1, 1981.

In addition to the above instruments, staff requires high range noble gas monitors be provided for the main condenser air ejectors (up to $10^5$ µCi/cc) and for atmospheric releases from the steam relief and safety valves (up to $10^3$ µCi/cc). By letter dated August 19, 1980, applicant has committed to install these monitors by January 1, 1981, if possible. A firm schedule for installation will be provided when available.

Clarification of post-accident monitoring instrumentation requirements, regarding containment pressure, water level and hydrogen concentration monitors, is being developed. This matter will be pursued with Alabama Power Company (the applicant) when additional guidance from staff becomes available.

We conclude that the applicant has taken adequate steps to date toward meeting this requirement.

II.F.2 Inadequate Core Cooling Instruments

Requirement

Install, if required, additional instruments or controls needed to supplement installed equipment in order to provide unambiguous, easy-to-interpret indication of inadequate core cooling.

This requirement shall be met by January 1, 1981. (See NUREG-0578, Section 2.1.3b and letters of September 27 and November 9, 1979.)

Discussion and Conclusions

The applicant has selected a reactor vessel level measurement as an additional instrument to indicate inadequate core cooling. By letter dated August 6, applicant described its schedule for installing a level measurement system using $^{10}BF_3$ neutron detectors mounted externally to the reactor. These are being developed and tested by National Nuclear Corporation under the sponsorship of Electric Power Research Institute. Tests of the level measurement system have been made at Trojan during the draining of water from the reactor. Alabama Power Power Company is planning to install a prototype system in Farley Unit 1 in October 1980, during a refueling outage. By letter dated August 19, 1980, applicant stated it would install an abbreviated prototype system on Unit 2 by January 1, 1981.

Water level measurement tests will be made on Unit 1 during forced outages, if any, and during the next refueling outage of Unit 1, planned for late 1981. Design and analysis of the system will be made concurrently with Unit 1 tests. The final system, modified by test experience, will be installed in Farley Unit 2 during the first refueling outage in mid-1982. If the boron neutron detector system is determined to be unacceptable based on Unit 1 tests, Alabama Power Company has committed to install an acceptable alternate system.

The staff has been monitoring the progress of all applicants and licensees in meeting schedule requirements of II.F.2 and has had meetings with suppliers of various level measurement systems to review the design and development progress and equipment procurement situation. Based on our continuing review of this situation, we expect that one or more alternate systems could be developed, procured, installed, and implemented well in advance of the mid-1982 installation proposed for Farley Unit 2. However, the staff agrees that all the proposed level measurement methods have inherent problems and that parallel development of several techniques is desirable. On the basis of its review of installation schedules for systems proposed by several licensees and applicants, the staff concludes that meeting the requirement to have a permanent level system installed by January 1, 1981 is not practical.

However, by January 1, 1981, we will require submittal of the documentation required by Table II.F.2-2, including an updated schedule and progress report on the development program. Based on our review of that submittal and other information available to the staff which is relevant to the proposed level measurement system, the staff will perform a preliminary evaluation of the proposed method for measuring reactor water level. Unless we can determine that the prospects for completing the development of an acceptable system by late 1981 are good, we will require that the schedule for procurement of an alternate system proceed in parallel, if necessary, in order to provide reasonable assurance that an acceptable system will be available for installation by late 1981. We will require that this system be installed at the earliest feasible date thereafter with due consideration for the impact on plant availability. The submittal of documentation for the development of this additional instrumentation will be made a cordition in the license.

We conclude that the applicant has taken adequate measures to date to provide instruments for monitoring inadequate core cooling at the earliest feasible date.

<u>Table II.F.2-2</u>

Information Required for Additional Instrumentation to Monitor Inadequate Core Cooling

1. By January 1, 1981, provide a report giving details and status of the proposed system for monitoring inadequate core cooling (ICC). The report should contain the necessary information, either by inclusions or by reference to previous submittals including pertinent generic reports, to satisfy the submittal requirements which follow:

    a. A description for the proposed final system including:

        (1) a design description of additional instrumentation (e.g., reactor vessel water level instruments) and displays;

(2) a detailed description of existing instrumentation systems (e.g., subcooling meters and in-core thermocouples), including parameter ranges and displays, which provide operating information pertinent to inadequate core cooling considerations; and

(3) a description of any planned modifications to the instrumentation systems described above.

b. The necessary design analysis, including evaluation of instruments to monitor water level, and available test data to support the design described in item 1.a.(2) above.

c. A description of additional test programs to be conducted for evaluation, qualification, and calibration of additional instrumentation.

d. An evaluation, including proposed actions, on the conformance of the inadequate core cooling instrumentation system to Regulatory Guide 1.97, Rev. 2. Any deviations should be justified.

e. A description of the computer functions associated with ICC monitoring and functional specifications for relevant software in the process computer and other pertinent calculators. The reliability of nonredundant computers used in the system should be addressed.

f. An updated schedule, including contingencies, for installation, testing and calibration, and implementation of any proposed new instrumentation or information displays.

g. Procedure guidelines for use of proposed additional instrumentation, and analyses used to develop these procedures.

h. A summary of key operator action instructions in the current emergency operating procedures for inadequate core cooling and a description of how these procedures will be modified when the final monitoring system is implemented.

i. A description and schedule for any additional submittals which are needed to support the acceptability of the proposed final instrumentation system and emergency operating procedures for inadequate core cooling.

III.A.1.2 Upgrade Emergency Support Facilities

Requirement

Provide radiation monitoring and ventilation systems, including particulate and charcoal filters, and otherwise increase the radiation protection to the onsite technical support center to assure that personnel in the center will not receive doses in excess of 5 rem to the whole body or 30 rem to the thyroid for the duration of the accident. Provide direct display of plant safety system parameters and call up display of radiological parameters.

For the near-site emergency operations facility, provide shielding against direct radiation, ventilation isolation capability, dedicated communications with the onsite technical support center, and direct display of radiological and meteorological parameters.

This requirement shall be met by January 1, 1981, although the safety parameter information requirements will be staged over a longer period of time. (See NUREG-0578, Section 2.2.2b and 2.2.2c, and letters of September 27 and November 9, 1979, and April 25, 1980.)

Discussion and Conclusion

Our discussion of the interim emergency support facilities is provided in Section 22.2 of this supplement. A permanent technical support center will be located in the auxiliary building, having a space of 22 feet by 65 feet, data monitoring and display equipment, communications equipment, and radiation monitoring and ventilation systems for protecting personnel from excessive doses. A permanent emergency operations facility under construction will accommodate 60 persons and have reliable onsite and offsite communications equipment. Completion of these permanent facilities is scheduled for January 1, 1981.

We conclude applicant has taken adequate steps to date toward meeting this requirement.

III.D.3.3 In-Plant Radiation Monitoring

Requirement

Provide the equipment, training, and procedures to accurately measure the radioiodine concentration in areas within the plant where plant personnel may be present during an accident.

This requirement shall be met before January 1, 1981. (See NUREG-0578, Section 2.1.8c, and letters of September 27 and November 9, 1979.)

Discussion and Conclusion

This requirement has been met as discussed in Section 22.2 of this supplement.

## 23.0 CONCLUSIONS

Based on our evaluation of the application as set forth in our Safety Evaluation Report dated May 2, 1975 and Supplement Nos. 1 through 3 and our evaluation as set forth in this supplement, we conclude that the operating license can be issued to allow fuel loading, zero power physics testing, and low power testing up to 5 percent of full rated power (2652 megawatts thermal) subject to license conditions which will require further Commission approval and license amendments prior to operation above zero power required for physics testing.

We conclude that the construction of the facility has been completed in accordance with the requirements of Section 50.57(a)(1) of 10 CFR Part 50, and that construction of the facility has been monitored in accordance with the inspection program of the Commission's staff.

Subsequent to the issuance of the operating license for 5 percent of full rated power for the Joseph M Farley Nuclear Plant Unit 2, the facility may then be operated only in accordance with the Commission's regulations and the conditions of the operating license under the continuing surveillance of the Commission's staff.

We conclude that the activities authorized by the license can be conducted without endangering the health and safety of the public, and we reaffirm our conclusions as stated in our Safety Evaluation Report.

## APPENDIX A

## SUPPLEMENT TO THE CHRONOLOGY OF THE RADIOLOGICAL SAFETY REVIEW

| | |
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| March 11, 1977 | Letter to applicant requesting reanalysis of the fuel handling accident. |
| June 3, 1977 | Letter from applicant providing information on environmental qualification of pressure transmitters. |
| August 5, 1977 | Letter to applicant transmitting Unit 1 License Amendment No. 2. |
| September 9, 1977 | Letter from applicant transmitting Amendment No. 67 to the FSAR. |
| September 30, 1977 | Letter to applicant requesting information concerning fracture toughness and the potential for Lamellar Tearing of steam generator and reactor coolant pump support material. |
| November 7, 1977 | Letter from applicant providing proposed design to account for degraded electrical grid conditions. |
| November 7, 1977 | Letter from applicant transmitting Amendment No. 68 to the FSAR. |
| December 19, 1977 | Letter from applicant providing information regarding the diesel generator operating status indication. |
| January 27, 1978 | Letter from applicant providing information on reactor vessel fracture toughness properties. |
| March 10, 1978 | Letter to applicant requesting information regarding the reactor vessel seal ring. |
| March 23, 1978 | Letter from applicant responding to our March 1978 request for information on the diesel generators. |
| March 30, 1978 | Letter from applicant providing information regarding the reactor vessel seal ring. |
| April 28, 1978 | Letter from applicant transmitting Amendment No. 69 to the FSAR. |
| May 19, 1978 | Letter from applicant providing information on environmental qualification of pressure transmitters. |

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| May 30, 1978 | Letter from applicant transmitting report entitled "Fracture toughness and potential for Lamellar Tearing of Steam Generator and Reactor Coolant Pump Materials." |
| June 2, 1978 | Staff memorandum summarizing visit to Farley 2 plant to examine containment sump areas and discuss sump tests. |
| June 8, 1978 | Letter to applicant requesting additional information for fuel handling accident. |
| June 20, 1978 | Letter from applicant reporting a problem with swing diesel generators for two-unit operation in accordance with 10 CFR 50.55(e). |
| June 23, 1978 | Letter from applicant providing information on the diesel generator operating status indication. |
| July 8, 1978 | Letter to applicant requesting information regarding a postulated fuel handling accident inside containment. |
| August 15, 1978 | Letter from applicant providing information regarding a fuel handling accident inside containment. |
| August 15, 1978 | Letter from applicant providing proposed corrective action to the problem with the diesel generators reported June 20, 1978. |
| August 25, 1978 | Letter from applicant transmitting Amendment No. 70 to the FSAR. |
| September 6, 1978 | Letter from applicant providing report evaluating Farley overpressure mitigating system. |
| September 19, 1978 | Letter to applicant requesting cooperation with Westinghouse in providing control rod guide tube wear data. |
| Septebmer 28, 1978 | Letter from applicant providing information an radioactive waste drumming station. |
| October 16, 1978 | Letter from applicant providing additional proposed corrective action to the problem identified in the June 20, 1978 letter. |
| November 3, 1978 | Letter from applicant responding to questions on overpressure mitigating system. |
| November 17, 1978 | Letter from applicant summarizing problem and corrective actions for the swing diesel generators. |
| November 27, 1978 | Letter to applicant requesting information regarding power grid voltage degradation. |

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| December 18, 1978 | Letter from staff consultants (U of Iowa) regarding results of review of model tests of Farley containment sump intakes. |
| December 20, 1978 | Letter from applicant providing modified design of DC power supplies for the auxiliary feedwater system. |
| December 29, 1978 | Letter from applicant transmitting Amendment No. 71 to the FSAR. |
| January 4, 1979 | Letter from applicant providing proposed changes to Unit 1 Technica Specifications to implement overpressurization mitigation system. |
| January 15, 1979 | Letter from applicant providing information regarding power grid voltage degradation. |
| February 13, 1979 | Letter to applicant transmitting Amendment No. 8 to NPF-2 (Farley 1) and safety evaluation of design changes to spent fuel pool. |
| February 21, 1979 | Letter to applicant advising that FSAR analysis of boron dilution bounds the recent boron dilution incident. |
| February 26, 1979 | Letter to applicant transmitting Amendment No. 9 to NPF-2 (Farley 1) and Security Plan Evaluation Report. |
| April 13, 1979 | Letter to applicant transmitting Amendment No. 11 to NPF-2 (Farley-1) and Fire Protection Safety Evaluation Report. |
| May 9, 1979 | Letter to applicant transmitting our Safety Evaluation of the Zirconium - Water correction to the ECCS Analysis for Unit 1. |
| June 15, 1979 | Letter from applicant providing informaton on feedwater lines. |
| July 24, 1979 | Letter from applicant providing information on feedwater lines. |
| July 31, 1979 | Letter to applicant providing Amendment No. 13 to Unit 1 License (NPF-2) regarding overpressurization protection. |
| September 17, 1979 | Letter from applicant providing secondary water chemistry monitoring program. |
| November 1, 1979 | Letter from applicant providing response to IE Bulletin 79-21 "Effects of Reference Leg Heatup." |
| December 12, 1979 | Letter from applicant providing schedule for completion of fire protection modifications. |

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| January 7, 1980 | Letter from applicant providing response to IE Bulletin 79-02, Revision 2, "Pipe Support Base Plant Designs Using Concrete Expansion Anchor Bolts." |
| January 25, 1980 | Letter to applicant requesting information regarding preservice testing of safety-related pumps and valves. |
| February 4, 1980 | Letter to applicant requesting information needed to perform a review of seismic qualification of safety-related electrical and mechanical equipment. |
| February 20, 1980 | Letter to applicant requesting information needed for confirmatory piping analysis and radiation protection evaluation. |
| February 21, 1980 | Letter to applicant requesting review of equipment qualification documentation to determine conformance to NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment." |
| March 7, 1980 | Letter from applicant transmitting Amendment No. 72 to the FSAR. |
| March 12, 1980 | Letter from applicant providing inservice testing program for ASME Code Class 1, 2 and 3 pumps and valves. |
| March 14, 1980 | Letter from applicant providing preservice inspection program for ASME Code Class 1, 2 and 3 Components. |
| March 17, 1980 | Letter from applicant providing information for confirmatory piping analysis. |
| March 17, 1980 | Letter from applicant providing information regarding the spent fuel transfer tube operation. |
| March 17, 1980 | Letter from applicant providing information on structural barriers and shielding near the spent fuel transfer tube. |
| March 20, 1980 | Letter to applicant requesting response to IE Bulletin 79-13, "Cracking in Feedwater System Piping." |
| April 1, 1980 | Letter to applicant requesting information regarding fuel and control rod performance. |
| April 4, 1980 | Letter from applicant providing information concerning seismic qualification of safety-related equipment. |
| April 7, 1980 | Letter from applicant transmitting Draft Farley Plant Radiological Technical Specifications. |

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| April 14, 1980 | Letter from applicant committing to perform inspections required by IE Bulletin 79-13, "Cracking in Feedwater System Piping." |
| April 14, 1980 | Letter from applicant providing information on spent fuel transfer tube radiation. |
| April 21, 1980 | Letter to all power reactor applicants and licensees requesting information on Seismic Category I masonry wall. |
| May 1, 1980 | Letter from applicant providing information on the adequacy of station electrical distribution system voltages. |
| May 5, 1980 | Letter to applicant requesting an audit of conformance to separation criteria of electrical equipment. |
| May 8, 1980 | Letter to applicant requesting information regarding floodplain near the Farley plant pursuant to Executive Order 11988. |
| May 12, 1980 | Letter from applicant providing information regarding fuel and control rod performance. |
| May 19, 1980 | Letter to applicant requesting information regarding radiation protection program. |
| May 27, 1980 | Letter from applicant advising of separation of electrical equipment and systems at Farley plant. |
| May 28, 1980 | Letter from applicant providing information regarding floodplain near Farley site. |
| May 28, 1980 | Letter from applicant describing its proposed modified startup physics test program. |
| June 3, 1980 | Letter from applicant providing information on spent fuel transfer tube shielding. |
| June 3, 1980 | Letter from applicant providing information regarding radiation protection. |
| June 10, 1980 | Letter from applicant providing results of its control room human factors and operations review. |
| June 11, 1980 | Letter from applicant responding to staff position on material for support pins for control rod guide tubes. |
| June 13, 1980 | Letter from applicant providing its response to IE Bulletin 80-06. |

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| June 13, 1980 | Letter to applicant requesting emergency operating procedures for anticipated transients without scram. |
| June 13, 1980 | Letter to applicant requesting informaton regarding vessel nozzle underclad cracking potential. |
| June 17, 1980 | Letter to applicant requesting information regarding inservice inspection. |
| June 19, 1980 | Letter to applicant requesting information regarding fracture toughness of reactor coolant system materials and preservice inspection program. |
| June 20, 1980 | Letter from applicant providing its "Response to TMI-2 Action Plan." |
| June 23, 1980 | Letter from applicant providing information regarding radioactive waste drumming station. |
| June 25, 1980 | Letter to all power reactor applicants and licensees Commission Memorandum and Order dated May 27, 1980 regarding fire protection for electrical cables and environmental qualification of electrical components |
| June 27, 1980 | Letter from applicant responding to staff positions on steam generator tube integrity. |
| June 30, 1980 | Letter from applicant providing detailed seismic qualification summary information for equipment selected for audit by the Seismic Qualification Review Team. |
| June 30, 1980 | Letter from applicant providing additional information regarding the containment purge system. |
| June 20, 1980 | Letter from applicant providing emergency operating procedure for anticipated transients without scram. |
| June 30, 1980 | Letter from applicant providing selected emergency operating procedures. |
| July 3, 1980 | Letter from applicant providing information regarding the preservice inspection program. |
| July 7, 1980 | Letter from applicant describing revisions to its modified startup physics test program. |

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| July 3, 1980 | Letter from applicant responding to our June 17, 1980 request for information regarding preservice inspection. |
| July 14, 1980 | Letter from applicant providing radwaste solidification process control program. |
| July 8, 1980 | Letter from applicant transmitting Amendment No. 73 to the FSAR. |
| July 14, 1980 | Letter to applicant requesting information regarding augmented low power test program. |
| July 14, 1980 | Letter from applicant providing information regarding offsite dose calculational model. |
| July 15, 1980 | Letter from applicant providing a response to TMI Requirements I.A.2.1, I.A.2.3, and I.A.3.1. |
| July 16, 1980 | Letter to applicant requesting information regarding containment emergency sump performance. |
| July 16, 1980 | Letter to applicant requesting information regarding its June 20, 1980 "Response to the TMI-2 Action Plan." |
| July 17, 1980 | Letter from applicant providing information for radiological technical specifications. |
| July 17, 1980 | Letter from applicant providing information regarding degraded power grid voltage. |
| July 17, 1980 | Letter from applicant providing information regarding reactor vessel water level measurement. |
| July 17, 1980 | Letter from applicant providing information regarding control room design review. |
| July 17, 1980 | Letter from applicant providing information regarding control room habitability. |
| July 17, 1980 | Letter from applicant providing qualification reports and seismic specifications for each of five pieces of equipment selected for confirmatory review by Seismic Qualification Review Team. |
| July 17, 1980 | Letter from applicant providing information on-in core thermocouples. |
| July 17, 1980 | Letter from applicant requesting low power operating license. |

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| July 17, 1980 | Letter from applicant providing information regarding augmented low power test program. |
| July 17, 1980 | Letter from applicant responding to IE Bulletin 79-27, "Loss of Non-Class IE Instrumentation and Control Power System Bus During Operation." |
| July 18, 1980 | Letter from applicant providing information regarding the bioassay program. |
| July 23, 1980 | Letter from applicant responding to our requirement for relief and safety valve tests. |
| July 24, 1980 | Letter from applicant providing information regarding interim procedures for calculating accidental releases. |
| July 24, 1980 | Letter from applicant providing information regarding incore thermocouples and core subcooling monitor. |
| July 25, 1980 | Letter from applicant providing information regarding containment purge system. |
| July 29, 1980 | Letter from applicant providing information regarding secondary coolant chemistry control program. |
| July 29, 1980 | Letter from applicant providing information regarding training for mitigating core damage. |
| July 30, 1980 | Letter from applicant providing information regarding degraded electrical power grid conditions. |
| July 30, 1980 | Letter from applicant providing response to staff questions on fracture toughness. |
| August 1, 1980 | Letter from applicant providing information regarding its response to the TMI-2 Action Plan Requirements (NUREG-0694). |
| August 5, 1980 | Letter from applicant providing information regarding the secondary coolant chemistry program. |
| August 6, 1980 | Letter from applicant providing additional information regarding its response to NUREG-0694 requirements. |
| August 6, 1980 | Letter from applicant providing information regarding application of new fuel rod burst model to ECCS analyses. |
| August 6, 1980 | Letter from applicant providing information on the Farley-2 low pressure turbine disc properties. |

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| August 7, 1980 | Letter from applicant providing schedule for Westinghouse review of startup test procedures. |
| August 7, 1980 | Letter from applicant providing information regarding degraded electrical power grid conditions. |
| August 7, 1980 | Letter from applicant providing information regarding shift manning. |
| August 7, 1980 | Letter from applicant providing information regarding containment sump performance. |
| August 8, 1980 | Letter from applicant providing information regarding independent safety engineering group. |
| August 13, 1980 | Letter from applicant providing draft emergency plan in accordance with NUREG-0694 full-power requirements. |
| August 14, 1980 | Letter from applicant providing information regarding Farley 2 shift staffing. |
| August 14, 1980 | Letter from applicant providing additional information regarding purge valve operability. |
| August 15, 1980 | Letter from applicant providing policy statement on safety. |
| August 18, 1980 | Letter from applicant providing additional information regarding schedule for completing installation of fire protection systems. |
| August 18, 1980 | Letter from applicant providing information regarding completion of fire protection equipment. |
| August 18, 1980 | Letter from applicant providing commitments to implement certain parts of the security plan. |
| August 19, 1980 | Letter from applicant providing information regarding shift manning, low power test procedures, high range radiation monitors, fire protection, and security. |
| August 19, 1980 | Letter from applicant providing information regarding development of a level system. |
| August 22, 1980 | Letter from applicant providing information regarding duties of Shift Supervisors. |
| August 28, 1980 | Letter from applicant providing results of Westinghouse review of pressure transmitters. |

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| September 8, 1980 | Letter from applicant providing additional information on shift manning. |
| September 12, 1980 | Letter from applicant transmitting Amendment 74 to the FSAR. |

APPENDIX B

SAFETY EVALUATION REPORT

JOSEPH M. FARLEY UNIT 2

PRESERVICE INSPECTION PROGRAM

## I. INTRODUCTION

For nuclear power facilities whose construction permits were issued on or after January 1, 1971, but before July 1, 1974, 10 CFR 50.55a(g)(2) specifies that components shall meet the preservice examination requirements set forth in editions of Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code and Addenda in effect six months prior to the date of the issuance of the construction permit. The provisions of 10 CFR 50.55a(g)(2) also state that components (including supports) may meet the requirements set forth in subsequent editions of this code and addenda which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein.

In a letter dated April 28, 1978, Alabama Power Company docketed Amendment 69 to the Joseph M. Farley Unit 2 FSAR which states that the original preservice inspection program was based on the requirements of the 1971 Edition through Winter 1971 Addenda of Section XI of the ASME Code for Class 1 components and the 1971 Edition through Summer 1972 Addenda of Section XI for Class 2 components. However, in consideration of the requirements of 10 CFR 50.55a(g), the Joseph M. Farley Unit 2 preservice inspection program was revised in Amendment 69 based on conformance with the requirements of the 1974 Edition through the Summer 1975 Addenda of Section XI. In letters dated April 21, 1980 and July 3, 1980, additional information was provided for their preservice inspection program which requested relief from certain requirements that the applicant determined were impractical. This additional information was incorporated into Amendment 73 of the FSAR dated July 8, 1980.

Therefore, this report evaluates the extent to which the Joseph M. Farley Unit 2 preservice inspection program complies with the requirements of the 1974 Edition through Summer 1975 Addenda of Section XI. As a result of our review of this information, we have determined that certain preservice examinations are impractical and that performing these required examinations would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Our basis for this conclusion is discussed in the subsequent paragraphs of this report.

## II. TECHNICAL EVALUATION CONSIDERATIONS

A. The Joseph M. Farley Unit 2 received a construction permit on August 16, 1972. In accordance with 10 CFR 50.55a, the preservice inspection must comply with the 1971 Edition through Winter 1971 Addenda of the Code. The preservice examination program for Class 1 components was originally based on this Code Addenda. The ASME first published rules for inservice inspection in the 1970 Edition of Section XI. No preservice or inservice inspection requirements existed prior to that date. Since the plant system design and ordering of long lead time components were well underway by the time the Section XI rules became effective, full compliance with the exact Section XI access and inspectability requirements of the Code was not always practical. The Alabama Power Company (the applicant) optionally revised the preservice program based on the requirements of the 1974 Edition through Summer 1975 Addenda in consideration of the updating requirements of 10 CFR 50.55a(g).

B. Verification of the as-built structural integrity of the primary pressure boundary is not dependent on the Section XI preservice examination. The applicable construction codes to which the Joseph M. Farley Unit 2 primary pressure boundary were fabricated contain examination and testing requirements which by themselves provide the necessary assurance that the pressure boundary components are capable of performing safely under all operating conditions reviewed in the FSAR and described in the plant design specification. As a part of these examinations the primary pressure boundary full penetration welds were volumetrically inspected (radiographed) and the system was subjected to hydrostatic pressure tests.

C. The intent of a preservice examination is to establish a reference or baseline prior to the initial operation of the facility. The results of subsequent inservice examinations can then be compared to the original condition to determine if changes have occurred. If review of the inservice inspection results shows no change from the original condition, no action is required. In the case where baseline data are not available, all indications must be treated as new indications and evaluated accordingly. Section XI of the ASME Code contains acceptance standards which can be used as the basis for evaluating the acceptability of such indications. Therefore, conservative disposition of defects found during inservice inspection can be accomplished even though preservice information is not available.

D. Other benefits of preservice examination include providing redundant or alternative volumetric inspection of the primary pressure boundary using a test method different from that employed during the component fabrication. Successful performance of a preservice examination also demonstrates that the welds so examined are capable of subsequent inservice examination using a similar test method.

In the case of Joseph M. Farley Unit 2, a large portion of the ASME Code-required preservice examination was performed. We have concluded that failure to perform a 100% preservice examination of the welds identified below will not significantly affect the assurance of the initial structural integrity.

E. In some instances where the required preservice examinations were not performed to full extent specified by the applicable ASME Code, we will require that these or suppl mental examinations be conducted as a part of the inservice inspection program. We have concluded that requiring these supplemental examinations to be performed at this time (before plant startup) would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The performance of supplemental examinations, such as surface examinations, in areas where volumetric inspection is difficult will be more meaningful after a period of operation. Acceptable preoperational integrity has already been established by similar Section III fabrication examinations.

In cases where parts of the required examination areas cannot be effectively examined because of a combination of component design or current inspection technique limitations, we will continue to evaluate the development of new or improved volumetric examination techniques. As improvements in these areas are achieved, we will require that these new techniques be made a part of the inservice examination requirements of those components or welds which received a limited preservice examination.

## III. EVALUATION OF RELIEF REQUESTS

We have reviewed the information submitted by the applicant in Amendment 73 and the additional information submitted on April 21, 1980 and July 3, 1980, in which relief was requested from certain preservice examination requirements. Based on this information and our review the design, geometry, and materials of construction of components, certain preservice inspection requirements identified below have been determined to be impractical, and imposing these requirements would result in hardships or unusual difficulties without a compensating increase in quality and safety.

Therefore, pursuant to 10 CFR Part 50, paragraph 50.55a(g)(2), our conclusions that these preservice requirements are impractical is justified as follows:

A. Calibration Block Material Selection for Pressurizer and Steam Generator, Primary Portions (Relief Requests A and G) and Secondary Portions (Relief Request O):

Code Requirement:

Relief Request A: Material from which the block is fabricated shall be from one of the following: 1) the component nozzle dropout; 2) the component prolongation; or 3) when it is not possible to fabricate the block from material taken from the component, it may be fabricated from a material of a specification included in the applicable examinations volumes of the component. The acoustic velocity and attenuation of such a block shall be demonstrated to fall within the range of straight beam longitudinal wave velocity and attenuation found in the unclad component.

Reference Section XI, Appendix I, Article I-3121.

Relief Request G: Appendix I, Article I-3122 requires "where the component material is clad, the calibration block shall be clad to nominal thickness ± 1/8 inch."

Relief Request O: Same as Relief Request A.

Code Deviation Request:

Relief Request A: A deviation was requested to substitute Article T-434.1.1 of Section V of the ASME Code, 1974 Edition, Winter 1976 Addenda which states that the material from which the block is fabricated shall be from one of the following: (1) nozzle dropout from the component, (2) a component prolongation, or (3) material of the same material specification, product form, and heat treatment as one of the materials being joined.

Relief Request G: A deviation was requested to use an unclad calibration block.

Relief Request O: Same as Relief Request A.

Reason For Request:

Relief Requests A and O: Requirements #1 and #2, Article I-3121, cannot be met. At the time the components were built, no excess material was saved for fabrication of calibration blocks.

Requirement #3 cannot be met because the Code assumes an "unclad component" when in fact all the components are clad on the inner surfaces.

Relief Request G: The calibration blocks for the ultrasonic examinations of the referenced components are not clad. However, the lack of cladding does not affect the calibration of the ultrasonic equipment. Only the top (O.D.) portions of the blocks are actually used in the calibrations. Specifically, three side-drilled holes, at depths of 1/4 T, 1/2 T and 3/4 T, are utilized.

The I.D. of the blocks contains a 2% T notch. However, it is only used for reference. The amplitude response from the notch is not required to be above a certain minimum. In fact, the amplitude is not even recorded. Cladding the blocks could cause the amplitude to either increase or decrease. In either case, the calibration would not be affected.

Staff Evaluation: The applicant has requested relief from specific provisions of Appendix I "Ultrasonic Examination" concerning the material selection and cladding of the calibration blocks used for the pressurizer and steam generator. Appendix I was first published in the Summer 1973 Addenda and is limited in scope to Class 1 and 2 ferritic vessels 2-1/2 inches and over in wall thickness. In the 1977 Edition of Section XI, Appendix I was superseded by Article 4 of Section V. Article T-434.1.1 of Section V, Winter 1976 Addenda, is the current requirement for calibration block material for these components in accordance with 10 CFR 50.55a(b). Therefore, we conclude that in Relief Requests A and O, the substitution of Article T-434.1.1 of Section V is an acceptable alternative provision that may be substituted in lieu of Article I-3121 of Section XI.

Relief Request G states that the preservice examination of these components was performed with a calibration block that was not clad. No recordable flaw indications were identifed. Conformance with the specific Code provision would require repeating the preservice examination with a Code-acceptable reference standard. We have determined that repeating the preservice examination is impractical and would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

We have evaluated the method used by the applicant to establish the ultrasonic "sensitivity" and the influence of cladding of the calibration block on the preservice examination results, i.e., detection of actual flaws that would be significant to the structural integrity of the component. We do not agree with the applicant's analysis that only the O.D. portion (unclad) of the block is actually used in the calibrations from our evaluation of Articles I-4421 and I-4422 of the Summer 1975 Addenda. The intent of Section XI is clearly to fabricate a basic calibration block which is representative of the component and to recognize in the examination procedure the adverse influence of component cladding on the detection and evaluation of flaw indications. Considering the availability of the fabrication radiography to establish the initial structural integrity, we conclude that the use of an unclad calibration block during ultrasonic examination from the external component surface would not prevent the identification of safety-significant flaws and, therefore, is acceptable for the preservice examination only.

During our evaluation of the applicant's initial 10-year inservice inspection program, we will evaluate the subject of calibration blocks. We will require an augmented inservice inspection provision that future examinations be performed with calibration blocks of the same material, specification (including cladding), product form, and heat treatment as the component base metal being examined unless the applicant can quantitatively demonstrate, by analysis or test data, that this provision would be impractical.

B. Pressurizer Nozzle-to-Vessel Weld Examination (Relief Request B), Examination Category B-D, Item B2.2

Code Requirements: The extent of examination of each nozzle shall cover 100% of the volume to be inspected as shown in figure IWB-2500D.

Reference Section XI, Table IWB-2600.

Code Deviation Request: Request relief from examination of 100% of area identified in figure IWB-2500D.

Reason for Request: The geometric configuration of the nozzle prevents ultrasonic examination from being performed from the nozzle side of the weld to the extent required by IWB-2600 as indicated by drawings provided by the applicant. The examination was performed from both the weld and shell surfaces. One hundred percent of the weld, heat affected zone, and the adjacent base metal were examined by angle beam from the vessel side of the weld. The design of the weld limits examination to 25% of the base metal from the nozzle side of the weld. In addition, the welds received a magnetic particle examination in those areas not scanned during the ultrasonic inspection.

Staff Evaluation: We have determined that part of the required Section XI examination is impractical because the existing geometric configuration limits the extent of the examination. We conclude that the limited Section XI examination, the volumetric examination performed during fabrication, and the hydrostatic test demonstrate an acceptable level of preservice structural integrity.

C. Steam Generator Nozzle-to-Safe-End Weld Examination (Relief Request C), Examination Category B-F, Item B3.3

Code Requirement: The examination areas shall include essentially 100% of the dissimilar metal welds (e.g., safe-end welds) between combinations of carbon, low alloy, or high tensile steels and stainless steels, nickel-chromium-iron alloys, nickel-copper alloys. This shall include the base material for. at least, one wall thickness beyond the edge of the weld.

Code Deviation: A deviation was requested from performing 100% of Code-required volumetric examination.

Reason for Request: Examination of the steam generator primary nozzle safe-end-to-pipe welds is limited by the nozzle geometry and surface condition and by the limited surface preparation of the pipe side of the weld. The surface on the pipe side of the weld, which is a cast elbow, is machined for a distance of approximately 5-1/2 inches from the edge of the weld. Examinations can be performed on the surface of the weld but are severely limited from the nozzle size by the configuration of weld buildup and weld overlay as indicated by drawings provided by the applicant.

Staff Evaluation: The design of the steam generator primary nozzle-to-safe-end weld limits volumetric examination to the pipe side of the weld and weld surface. The applicant estimates that 100% of the weld root and 90% of the safe-end-to-nozzle weld can be examined.

We have determined that the Code examination of 100% of the dissimilar metals welds is impractical because the design of the nozzle and the as-built surface condition limits the examination coverage. To perform the volumetric examination to the maximum extent possible, the applicant performed UT from both the pipe side and the weld surface in accordance with Paragraph T-532 of Section V. Based on our review of the existing design, the preservice examination requirements, and the limited examinations performed by the applicant, we conclude that completing the remaining portion of the required examination is impractical and would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

During an evaluation of the applicant's initial 10-year inservice inspection program, we will evaluate the applicable Code-required volumetric and surface examinations for the steam generator dissimilar metal welds including the evaluation of an augmented inservice inspection program regarding the frequency of the design-limited ultrasonic examination.

D. ASME Class 1 Circumferential Butt Welds (Relief Request D), Examination Category B-J, Item B4.5

Code Requirements: The examination areas shall include essentially 100% of the longitudinal and circumferential welds and the base metal for one wall thickness beyond the edge of the weld. Longitudinal welds shall be examined for at least one foot from the intersection with the edge of the circumferential weld selected for examination. In the case of pipe branch connections, the areas shall include the weld metal, the base metal for one pipe wall thickness beyond the edge of the weld on the main pipe run, and at least two inches of the base metal along the branch run.

Code Deviation Request: A deviation was requested from performing 100% of the required volumetric examination for welds with access limitations due to design.

Reason for Request: Instances occur where pipe welds are between fittings, such as elbow-to-valve or flange-to-elbow welds. In such instances, access may be severely limited and ultrasonic examinations cannot be performed on 100% of the volume of the weld and the heat affected zone.

Staff Evaluation: We have evaluated the degree of accessibility and inspectability of the welds and the extent of examination estimated by the applicant as follows:

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| Loop 1 RTD return, weld #16 | - 40% |
| Loop 1 Cold Leg SIS, weld #8 | - 60% |
| Pressurizer Spray, welds #42 | - 70% |
| #43 | - 70% |
| Loop 3 RTD Return, weld #3 | - 60% |
| Pressurizer Relief, weld #14 | - 50% |
| Pressurizer Safety, welds #2 | - 70% |
| #5 | - 80% |
| #12 | - 70% |
| #16 | - 80% |
| #20 | - 80% |
| #24 | - 70% |
| #27 | - 80% |

Pressurizer Safety welds #29, 31, and 32 are inaccessible. However, field data in the form of radiography and dye penetrant will be utilized for the preservice inspection as allowed by IWB-2100(b).

We have determined that examination of these welds to the extent required by the Code is impractical due to the design of the piping system and/or location of piping hangers and supports. The applicant conducted surface examinations on those areas which cannot be completely scanned by the ultrasonic inspection. We conclude that the limited Section XI examinations, the volumetric examinations performed during fabrication, and the hydrostatic test demonstrate an acceptable level of preservice structural integrity.

E. Integrally Welded Supports (Relief Request E), Examination Category B-K-1, Item B 4.9

Code Requirement: The examination areas shall include essentially 100% of the integrally welded external support attachments. This includes the welds to the pressure-retaining boundary and the base metal beneath the weld zone and along the support attachment member for a distance of two support thicknesses.

Code Deviation Request: A deviation was requested from performing the entire Code-required volumetric examination. The applicant proposes to supplement the examination with a surface examination.

Reason for Request: The piping systems' integrally welded supports are attached to the pipes by fillet welds. The configurations of these welds are such that examinations cannot be performed to the extent required by IWB-2600. Only the base material of the pipe wall and the base metal of the support attachment can be volumetrically examined.

Staff Evaluation: We have determined that fillet welds for piping support attachments generally cannot be examined by ultrasonic techniques to the extent required by the Section XI and, therefore, the examination is impractical because of inherent limitations in the examination method. Based on the loading conditions of these types of welds during service, flaws would most likely be generated at the weld surface and thus be detectable by surface examination. Therefore, we conclude that a surface examination of the fillet welds is an acceptable alternative that may be used to supplement the limited volumetric examination.

F. ASME Class 1 Pipe Branch Connections Exceeding Six Inches in Diameter (Relief Request F), Examination Category B-J, Item B4.6

Code Requirement: The examination areas shall include essentially 100% of the longitudinal and circumferential welds and the base metal for one wall thickness beyond the edge of the weld. Longitudinal welds shall be examined for at least one foot from the intersection with the edge of the circumferential weld selected for examination. In the case of pipe branch connections, the areas shall include the weld metal, the base metal for one pipe wall thickness beyond the edge of the weld on the main pipe run, and at least two inches of the base metal along the branch run.

Code Deviation Request: A deviation was requested from performing 100% of the Code-required volumetric examination.

Reason for Request: The geometric configuration of the weld surface prevents ultrasonic examinations from being performed to the extent required by IWB-2600 as indicated by drawings provided by the applicant. Examinations were performed to the extent practical from the pipe and nozzle surfaces adjacent to the weld. Surface examinations of the weld were performed to supplement the volumetric examination.

Staff Evaluation: We have evaluated the degree of accessibility and inspectability of the welds and the extent of examination estimated by the applicant as follows:

Reactor Coolant Loop #1, weld #16BC - 80%
Reactor Coolant Loop #1, weld #21BC - 80%
Reactor Coolant Loop #2, weld #16BC - 80%
Reactor Coolant Loop #2, weld #21BC - 80%
Reactor Coolant Loop #3, weld #16BC - 80%
Reactor Coolant Loop #3, weld #21BC - 80%

We have determined that part of the required Section XI examination is impractical because the existing geometric configuration limits the extent of the examination. The applicant conducted surface examinations on those areas which cannot be completely scanned by the ultrasonic inspection. We conclude that the limited Section XI examinations, the volumetric examinations performed during fabrication, and the hydrostatic test demonstrate an acceptable level of preservice structural integrity.

G. Nozzle-to-Vessel Welds on Residual Heat Removal Heat Exchangers (Relief Request H), Examination Category C-B, Item C1.2

Code Requirement: The volumetric examination shall cover at least 20% of each circumferential weld, uniformly distributed among three areas around the vessel circumference.

Code Deviation Request: A deviation was requested to delete the required volumetric examination.

Reason for Request: The nozzle-to-vessel welds of the residual heat exchangers are covered by a reinforcement ring and are not accessible for examination as required by IWC-2600 as indicated by drawings provided by the applicant. The geometric configuration is such that alternative NDE methods cannot be substituted.

Staff Evaluation: We have determined that the as-built design configuration makes the Code-required examination impossible to perform. The weld required to be examined is totally covered by a reinforcement ring that is fillet welded to the nozzle, thus precluding volumetric examination. We conclude that removal of the welded reinforcement ring to make the weld accessible for examination is impractical and would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety because the initial preservice structural integrity has been demonstrated by the construction code examinations and hydrostatic test.

During our evaluation of the applicant's initial 10-year inservice inspection program, we will require an augmented inservice inspection program including surface examination of the fillet welds attaching the reinforcement ring to the nozzle and visual examination during hydrostatic tests.

H. Vessel Head-to-Shell and Flange-to-Shell Welds on: Seal Water Heat Exchanger; Letdown Reheat Exchanger; Reactor Coolant Filter; and Seal Water Return Filter (Relief Request I), Examination Category C-A, Item C 1.1

Code Requirement: The volumetric examination shall cover at least 20% of each circumferential weld, uniformly distributed among three areas around the vessel circumference.

Code Deviation Request: A deviation was requested from performing the volumetric examination required by Code.

Reason for Request: The thickness of the materials utilized for the construction of this component (0.165 to 0.185 inches) is such that meaningful results could not be expected with ultrasonic examination as required by IWC-2600. Surface and visual examination of these welds will be performed as an alternative method.

Staff Evaluation: We have determined that the Code-required examination is impractical because of inherent limitations in the examination method for these thin-wall (0.165 to 0.185 inches) components. We conclude that a surface and visual examination is an acceptable alternative examination that may be substituted in lieu of the required volumetric examination of at least 20% of each circumferential weld.

I. Primary Pressure Boundary (Relief Request J & K), Examination Categories C-F and C-G, Item C2.1

Code Requirement: Volumetric examination of circumferential butt welds and branch connections exceeding four-inch diameter including the weld metal and base metal for one-wall thickness by a sampling procedure defined in IWC-2520.

Code Deviation Request: A deviation was requested from performing 100% of the volumetric examination required by the Code.

Reason for Request: The arrangement and details of the Class 2 piping system and components were designed and fabricated before the examination requirements of Section XI of the Code were formalized, and some examinations as required by IWC-2600 are limited or not practical due to geometric configuration or accessibility. Generally these limitations exist at all fitting-to-fitting welds such as elbow to tee, elbow to valve, reducer to valve, etc. where geometry and sometimes surface conditions preclude ultrasonic couplings or access for the required scan length. The limitations exist to a lesser degree at pipe-to-fitting welds, where examination can only be fully performed from the pipe side, the fitting geometry limiting or even precluding examination from the opposite side. The welds will be ultrasonically examined by angle beam to the extent allowed by geometric configuration; however, 100% of the weld material will be examined. Also, surface examinations will be performed to supplement the limited volumetric examinations.

In instances of branch pipe-to-pipe welds, ultrasonic examinations cannot be performed on the surface of the weld. Surface examinations will be performed on 100% of the weld and adjacent base material.

In instances where the locations of pipe supports or hangers restrict the access available for the examination of pipe welds as required by IWC-2600, examinations will be performed to the extent practical unless removal of the support is permissible without unduly stressing the system.

Staff Evaluation: We have evaluated the degree of accessibility and inspectability of the welds and the extent of examination estimated by the applicant as follows:

RHR, welds #31 - 50%
#32 - 50%
#14 - 90%
#11 - 30%
#20 - 30%
#18 - 50%

Main Steam welds #4-14 - 80%
#4-15 - 80%
#1-5 - 80%
#1-11 - 80%
#1-12 - 80%
#1-13 - 80%
#1-14 - 80%
#1-15 - 80%
#1-16 - 80%
#1-17 - 80%
#2-5 - 80%
#2-11 - 80%
#2-12 - 80%
#2-13 - 80%
#2-14 - 80%
#2-15 - 80%
#2-16 - 80%
#2-17 - 80%
#3-5 - 80%
#3-11 - 80%
#3-12 - 80%
#3-13 - 80%
#3-14 - 80%
#3-15 - 80%
#3-16 - 80%
#3-17 - 80%

We have determined that examination of these welds to the extent required by the Code is impractical due to the design of the piping system and/or location of piping hangers and supports. The applicant conducted surface examinations on those areas which cannot be completely scanned by the ultrasonic inspection.

We conclude that the limited Section XI examinations, the nondestructive examinations performed during fabrication, and the hydrostatic test demonstrate an acceptable level of preservice structural integrity.

J. Regenerative Heat Exchanger (Relief Requests L and N) and Excess Letdown Heat Exchanger and Letdown Heat Exchanger (Relief Request N), Examination Category C-A, Item C1.1

Code Requirement: The volumetric examination shall cover at least 20% of each circumferential weld, uniformly distributed among three areas around the vessel circumference.

Code Deviation Request:

Relief Request L: A deviation was requested to examine the regenerative heat exchanger using the half-node technique to the extent practical.

Relief Request N: A deviation was requested to change the distribution of the examination sample.

Reason for Request:

Relief Request L: The regenerative heat exchanger shell is fabricated from centrifugally cast austenitic steel material which limits ultrasonic examination as required by IWC-2600 to the half-node techniques. The geometric configuration of the weld surface and the location of adjacent nozzles and supports limit the extent of the examination coverage. Surface examinations will be performed to supplement the volumetric examinations.

Relief Request N: The location of nozzles and supports limits the extent of examination coverage. Consequently, the requirements for three uniformly distributed areas cannot be met. One or two areas will be inspected, as accessibility permits, instead of the required three areas. The required 20% of each circumferential weld will be volumetrically examined except where material thickness precludes ultrasonic testing as stated in Relief Request (I).

Staff Evaluation:

Relief Request L: We have determined that the Code-required examination is impractical because of inherent limitations in the examination method for centrifugally cast stainless steel and limitations to the extent of the examination coverage as a result of the existing design. The applicant conducted surface examinations on those areas which cannot be completely scanned by the ultrasonic inspection. We conclude that the limited Section XI examinations, the nondestructive examinations performed during fabrication, and the hydrostatic test demonstrate an acceptable level of preservice structural integrity.

Relief Request N: We have determined that the Code requirement that the examination sample be uniformly distributed is impractical because of the limitations in the existing design. We conclude that the examinations of one or two areas is an acceptable alternative examination that may be substituted in lieu of a uniform distribution because the extent of examination is the same. The examination method shall be as specified in the Code or Relief Requests I and L as applicable.

K. Charging Pumps Integrally Welded Supports (Relief Request M), Examination Category C-E-I, Item C3.3

Code Requirement: Surface examination of 100% of the major load bearing element.

Code Deviation Request: A deviation was requested to perform less than 100% of examination area required by the Code.

Reason for Request: Due to component and support designs, approximately 20% of each integrally welded support is inaccessible for examination.

Staff Evaluation: We have determined that the examination of these integrally welded supports to the extent required by the Code is impractical because of the existing design, and the initial preservice structural integrity has been demonstrated by the nondestructive examinations performed during fabrication. Therefore, we conclude that imposition of the exact Code requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

## IV. CONCLUSIONS

Based on the foregoing, we have determined, pursuant to 10 CFR Part 50, paragraph 50.55a(a)(2), that certain Section XI required preservice examinations are impractical, and compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

Our technical evaluation has not identified any practical method by which the existing Joseph M. Farley Unit 2 can meet all the specific preservice inspection requirements of Section XI of the ASME Code. Requiring compliance with all the exact Section XI required inspections would delay the startup of the plant in order to redesign a significant number of plant systems, obtain sufficient replacement components, install the new components, and repeat the preservice examination of these components. Examples of components that would require redesign to meet the specific preservice examination provisions are certain steam generator nozzles, certain pressurizer nozzles, and a significant number of the piping and component support systems. Even after the redesign effort, complete compliance with the preservice examination requirements probably could not be achieved. However, the as-built structural integrity of the existing primary pressure boundary has already been established by the construction code fabrication examinations.

Based on our review and evaluation we conclude that the public interest is not served by imposing certain provisions of Section XI of the ASME Code that have been determined to be impractical. Pursuant to 10 CFR 50.55a(a)(2), we have allowed deviations from these requirements which are impractical to implement and would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. We conclude that the Joseph M. Farley Unit 2 preservice examinations meet the requirements of the 1974 Edition through Summer 1975 Addenda of Section XI of the ASME Code to the extent practical and is in compliance with 10 CFR 50.55a(g)(2).

# 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, inter alia, 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 FSAR 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 time span, 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 and as applied to an operating license proceeding Virginia Electric and Power Company (North Anna Nuclear Power Sation, Units 1 and 2), ALAB-491, NRC 245 (1978).

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 was

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

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)[2/]
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 "Unresolved Safety Issues" are not applicable to Farley Unit 2 and six of these tasks (A-6[3/], A-7, A-8, A-39, A-10 and A-42) are peculiar to boiling water reactors. With regard to the remaining 14 tasks that are applicable to Farley Unit 2, the NRC staff has issued NUREG reports providing its proposed resolution of five of the issues. Each of these have been addressed in the Farley Unit 2 SER and/or Supplements or will be addressed in a future supplement. The table below lists those issues and the SER/SER Supplement section in which they are discussed.

| Task Number | NUREG Report and Title | SER/SER Supplement Section |
|---|---|---|
| A-12 | NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports" | Discussed below |
| A-24 | NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment" | 7.7.2 of this Supplement |
| A-26 | NUREG-0224, "Reactor Vessel Pressure Transient Protection for Pressurized Water Reactors" and RSB BTP 5-2 | 5.4.2 of this Supplement |
| A-31 | Regulatory Guide 1.139, "Guidance for Residual Heat Removal" and RSB BTP 5-1 | Will be addressed in future supplement |
| A-36 | NUREG-0612, Control of Heavy Loads at Nuclear Power Plants | Section 9.2.4 of the SER and Section 9.2.4 of Supplement No. 2 to the SER |

[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 address 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.

[3/] Task A-6 was completed in December 1977.

A-12 Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports

NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports," was issued for comment in November 1979. This report summarizes work performed by the Nuclear Regulatory Commission staff and its contractor Sandia Laboratories in the resolution of the generic activity. The report describes the technical issues, the technical studies performed by Sandia Laboratories, the NRC staff's technical positions based on these studies, and the staff's plan for implementing its technical positions. As a part of initiating the implementation of the findings in this report, letters were sent to all applicants and licensees including Farley 2 on May 19 and 20, 1980. In these letters a revised proposed implementation plan was presented and specific criteria for material qualifications were defined.

Many comments on both the Draft NUREG-0577 and the letters of May 19 and 20 have been received by the staff and detailed consideration is presently being given to these comments. After completing its review and analysis of the comments provided, the staff will issue a final NUREG-0577 which will include a full discussion and resolution of the comments and a final plan for implementation.

The staff has estimated that its implementation review will require approximately two years. Since many factors (initiating event, low fracture toughness in a critical support member in tension, low operating temperature, large flaw) must be simultaneously present for failure of the support system to ensue the staff has determined that licensing for pressurized water reactors should continue during the implementation phase. Our conclusions regarding licensing and subsequent operation are not sensitive to the estimated length of time required for this work.

With regard to the lamellar tearing issue, the results of an extensive literature survey by Sandia revealed that, although lamellar tearing is a common occurrence in structural steel construction, virtually no documentation exists describing inservice failures due to lamellar tearing. Nonetheless, additional research is recommended to provide a more definitive and complete evaluation of the importance of lamellar tearing to the structural integrity of nuclear power plant support systems.

The remaining issues applicable to the Farly Unit 2 are listed in the following table:

GENERIC TASKS ADDRESSING UNRESOLVED SAFETY ISSUES
THAT ARE APPLICABLE TO THE JOSEPH M. FARLEY NUCLEAR PLANT, 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 Interactions in Nuclear Power Plants

7. A-40 Seismic Design Criteria
8. A-43 Containment Emergency Sump Reliability
9. A-44 Station Blackout

With the exception of Tasks A-9, A-43 and A-44, 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 technical resolution for Task A-9 is completed and a proposal for rulemaking is in preparation. A Task Action Plan for Task A-44 has been approved and issued. A Task Action Plan for Task A-43 is near completion. 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 9 "Unresolved Safety Issues" listed above as they relate to Farley Unit 2. Discussion of each of these issues including references to related discussions in the Safety Evaluation Report and 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 the Farley 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." The NRC staff has not performed an in-depth review to identify new issues however 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 Farley Unit 2 have been identified and are discussed in 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 the Farley plant.

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 is being performed by the staff and the Commission. A special report will be provided to the Congress after completion of this review, 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 Farley 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 types of water hammer events are addressed in Supplement No. 1 to the SER for Farley Units 1 and 2 in Section 10.5 at page 19 and in Supplement No. 2 in Section 10.5 at page 19. System design changes and testing requirements necessary to prevent this type of water hammer are discussed. In Section 10.5, we concluded that, subject to confirmation during the preoperational test program, the feedwater system and steam generator design for Farley Units 1 and 2 with respect to this potential water hammer concern is 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 Farley Units 1 and 2 SER, we require that the applicant conduct a preoperational vibration dynamic effects test program in accordance with Section III of the ASME Code for all ASME Class 1 and Class 2 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 pipe 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 SER and Supplements Nos. 1 through 4 and protection against the dynamic effects of such pipe breaks inside and outside of containment is provided as described in Section 3.6 of the SER and Supplement No. 1.

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 Farley 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 Farley 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 a light water reactor, 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 identified in May 1975 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 Farley facility. Our evaluation and conclusions are provided in Section 3.9.1 at pages 3-1 and 3-2 of the Farley SER. Accordingly, we have concluded that Farley 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 (wastage) has been observed in several Westinghouse plants for a number of years. Plants operating exclusively with an all volatile secondary water treatment process have not exprienced this form of degradation to date. 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 steam generator design features and a secondary water chemistry control and monitoring program, that the applicant has employed to minimize the onset of steam generator tube problems are described in Section 10.5 of Supplement No. 2 to the SER and in Section 5.9 of this supplement. In addition, Section 5.9 of this supplement discusses the inservice inspection requirements. As described in Section 5.9 of this supplement, the applicant has 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 Farley Unit 2 should minimize the steam generator tube problems encountered. Further the inservice inspection and Technical Specification requirements will assure that the applicant 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 applicant at Farley Unit 2 after operation begins, if necessary.

Based on the foregoing, we have concluded that Farley 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 applicant prior to operation of Farley Unit 2 are discussed in Section 5.4.1 of this supplement.

Based on our review, we have concluded that there is reasonable assurance that Farley Unit 2 can be operated prior to ultimate resolution of this generic issue without endangering 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, and accident conditions over the life of the plant. 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, relative to required margins at normal full power after comparatively short periods of operation. In addition, results from analyses performed by PWR 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. 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.

Based upon our evaluation of the Farley Unit 2 reactor vessel materials toughness, we have concluded that this unit will have adequate safety margins against brittle failure during operating, testing, maintenance and anticipated transient conditions over the life of the units. However, some PWR's in the later stages of licensing have the potential, after many years of operation, to have marginal fracture toughness for the postulated accident conditions. When Task Action Plan 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 well in advance of the Farley Unit 2 reactor vessel reaching a level of marginal fracture resistance, acceptable vessel integrity for the postulated accident conditions will be assured at least until the reactor vessel is reevaluated for long-term acceptability.

Therefore, based upon the foregoing, we have concluded that Farley Unit 2 can be operated prior to resolution of this generic issue without undue risk to the health and safety of the public.

A-17 Systems Interactions 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 multi-disciplinary 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.

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 Farley Unit 2 can be operated prior to the ultimate resolution of this generic issue without endangering 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 Commission. 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 SRP sections and Regulatory Guides to bring them more in line with the state-of-the-art will result.

As discussed in Section 3.7 of the SER the seismic design basis and seismic design of Farley Unit 2 have been evaluated at the operating license stage and have been found acceptable. We do not expect the results of Task A-40 to affect these conclusions because the techniques under consideration were essentially utilized in the Farley review. Accordingly, we have concluded that Farley Unit 2 can be operated prior to ultimate resolution of this generic issue without endangering 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 to 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 address 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 required to allow insulation to settle out before reaching the sump screening; and it is required that the sump 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. Both in-plant and scale model tests have been performed by applicants to demonstrate that circulation through the sump can be reliably accomplished.

As indicated in Section 6.3.3 of this supplement, the applicant has performed out-of-plant scale model tests of the Farley Unit 2 containment sump design. The test identified the need for several design modifications that were subsequently incorporated into the plant design. The applicant has demonstrated that there is reasonable assurance that the sump design would perform as expected following a LOCA and therefore is acceptable.

The near term implementation of Task-A-43 for Farley Unit 2 is expected to be procedural in nature and assure adequate housekeeping and emergency procedures to supplement the sump tests discussed above. Accordingly, we have concluded that Farley Unit 2 can be operated prior to ultimate resolution of this generic issue without endangering 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 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 PWR analyzed in the Reactor Safety Study (WASH-1400). The steam turbine driven auxiliary feedwater pump for the PWR analyzed in WASH-1400 had no ac 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 Farley Unit 2. Nonetheless, the combination of design, operation, and testing requirements that have been imposed on the applicant will assure that these units will have substantial resistance to a loss of all ac and that even if a loss of all ac 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 Farley Unit 2 SER and Section 8.2 of this supplement.

If offsite ac power is lost, five diesel generators and their associated distribution systems will deliver emergency power to safety-related equipment for both Units 1 and 2. Our review of the design, testing, surveillance, and maintenance provisions for the Farley Unit 2 onsite emergency diesels are described in Section 8.3.1 of the SER, Section 8.3.1 of Supplement No. 1 and Section 8.3.1 of this supplement. Our requirements include preoperational testing to assure the reliability of the installed diesel generators in accordance with our requirements discussed in the Farley Unit 2 SER. In addition, the applicant has 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 9.3.1 of Farley Unit 2 SER and Section 9.3.1 of Supplement Nos. 1, and 2 and Section 9.3.1 of this supplement.

Based on our review, we have concluded that there is reasonable assurance that Farley Unit 2 can be operated prior to the ultimate resolution of this generic issue without endangering the health and safety of the public.

FEDERAL EMERGENCY MANAGEMENT AGENCY

Washington D.C. 20472

AUG 28 1980

Mr. Harold Denton
Director, Office of Nuclear
Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Mr. Denton:

We have been advised that Unit #2 of the Farley power station of the Alabama Power Company System is ready to commence low power operation and that the Nuclear Regulatory Commission (NRC) staff is prepared to recommend such operation.

The Federal Emergency Management Agency (FEMA) acknowledges the existing state of emergency planning and preparedness related to the Farley nuclear facility. FEMA has initiated actions to assist the State of Alabama and its local governments in the development of radiological emergency response plans consistent with the NRC/FEMA criteria. Alabama presently plans to submit its revised plan for Regional Assistance Committee (RAC) review before September 15, 1980. Early County, Georgia is also working on the site specific aspects of the Farley station and will be submitting its revised plan to the RAC shortly. Florida's plan has previously received NRC concurrence under the previous policy.

FEMA recognizes that the Farley/Alabama emergency planning and preparedness situation is a special case caught in the transition between old and new emergency planning criteria for both nuclear facilities, State and local governments, and additionally during the transition of the responsibilities between NRC and FEMA.

Based upon our policy agreement of March 1980, concerning low power testing, and our knowledge of the present condition of the State of Alabama and Early County, Georgia, emergency plans, your staff's recommendation for licensing to permit low power testing appears to be reasonable.

Sincerely yours,

John W. McConnell

John W. McConnell
Assistant Associate Director
for Population Preparedness

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U.S. NUCLEAR REGULATORY COMMISSION

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Supplement No. 4 to the Safety Evaluation Report of Alabama Power Company's application for licenses to operate its Joseph M. Farley Nuclear Plant, Units 1 and 2, located in Houston County, Alabama, has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. This Supplement provides the NRC staff's evaluation of Alabama Power Company's FSAR Amendment Nos. 67 through 74 for the Farley Nuclear Plant, and its reponse to other safety issues, including the TMI-2 Action Plan, that have arisen since Supplement No. 3 was issued in June 1977. The staff concluded that the Farley Nuclear Plant, Unit 2, may be issued a license for fuel loading and low power testing.

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