Docket No. 50-458

JUL 26 1985

Mr. William J. Cahill, Jr.
Senior Vice President
River Bend Nuclear Group
Gulf States Utilities Company
P.O. Box 2951
Beaumont, Texas 7704
Attention Mr. J. E. Booker

Dear Mr. Cahill:

SUBJECT: DRAFT SAFETY EVALUATION REPORT SUPPLEMENTS FOR THE RIVER BEND STATION UNIT 1

On July 25, 1985, you were requested to certify the Technical Specification for River Bend Station, Unit No. 1 that to the best of your knowledge, the Technical Specifications accurately reflect the plant FSAR, the staff's SER and the as built configuration of the plant. However, to meet your licensing schedule, given the major recent changes in the FSAR, the staff is working to complete the SER at the same time you are reviewing the Technical Specifications. Therefore, we are enclosing draft material from SER Supplements 2 and 3 to assist you in your review of the Technical Specifications. However, this material is draft and subject to modification.

Please contact the NRC Project Manager Stephen M. Stern, for clarification or further discussion on this topic.

Sincerely,

Walter R. Butler, Chief
Licensing Branch No. 2
Division of Licensing

Enclosure: As stated

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WASHINGTON, D. C. 20555

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Gulf States Utilities Company

River Bend Nuclear Plant

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2 SITE CHARACTERISTICS

2.2 Nearby Industrial, Transportation, and Military Facilities

2.2.2 Nearby Facilities

In view of current oil and gas exploration in the region of the plant site, the applicant's letter of May 28, 1985, indicates its agreement to notify the Commission within 30 days of any plans for wells or pipelines within a 2-mile radius of the River Bend Station, Unit 1, reactor centerline. The notification will address the potential safety of the wells or pipelines on the River Bend Station. Therefore, License Condition 1 is no longer required.

2.3 Meteorology

2.3.3 Onsite Meteorological Measurements Program

The emergency plan, including the meteorological monitoring program, has been reviewed and evaluated by the staff. The meteorological portions of the plan are acceptable. The acceptability of the implementation of the program is evaluated in IE Report No. 458/85-05.

2.4 Hydrologic Engineering

2.4.3 Probable Maximum Flood on Streams and Rivers

2.4.3.3 West Creek Flood Potential

In the SER the applicant was required to remove temporary road crossings and sediment from West Creek before beginning station operation. This work has been completed and is described in the May 13, 1985 letter from the applicant.

The applicant has also committed to an inspection and maintenance program for the Fabriform lined section of West Creek (June 10, 1985, letter). The applicant will inspect the creek at least once a year. If sediment buildup exceeds 1 foot in depth the creek will be cleaned.

The staff now concludes that the applicant has met the requirements of the staff in regard to preventing flooding from West Creek.

2.4.11 Cooling Water Supply

2.4.11.2 Emergency Cooling Water Supply

Since Supplement 1 of the SER was published, the applicant has made significant changes in the operation of the standby mechanical draft cooling tower. The cooling tower fans will no longer go on automatically in the event of an accident requiring emergency cooling. Instead, the fans will be started manually, after a delay, to reduce the load on the diesel generators. The applicant has stated that following a design-basis accident, during the worst meteorological

conditions (as specified in RG 1.27) a delayed fan start of up to 2 hours will still maintain tower return temperatures below the design basis temperature of 95°F. The staff's contractor, Argonne National Laboratory (ANL), has completed an analysis which independently confirms the applicant's calculations. The staff concludes that the plant still meets RG 1.27 and GDC 44 even with the delayed fan start. However, the staff is still reviewing the heat input from the plant to determine the maximum water temperature with delayed fan start. Staff confirmation of this temperature will be provided in a future SER supplement.

2.5 Geology, Seismology, and Geotechnical Engineering

The staff has reviewed the applicant's submittals on (1) the stability of slopes caused by Unit 2 excavation and (2) the sliding stability of the service water tunnel that leads to Unit 2. Although Unit 2 has now been canceled, the tunnel continues to retain and support foundation soils required for Unit 1 operation. The staff has evaluated these submittals in accordance with the relevant criteria described in Appendix A to 10 CFR 50, Appendix A to 10 CFR 100, Regulatory Guide 1.70 (Rev. 3), and the Standard Review Plan (NUREG-0800), July 1981.

2.5.5 Stability of Slopes

After canceling Unit 2, the applicant decided not to backfill the Unit 2 excavation pit that now exists adjacent to the Unit 1 structures. This pit is approximately 30 ft below Unit 1 plant grade (el 94 ft) and covers a horizontal area of approximately 300 ft by 300 ft as shown in FSAR Figure 2.5-72a. Since the staff raised certain concerns regarding the effect of precipitation and runoff ponding in the pit (NUREG-0989), the applicant has evaluated the impact of this ponding on the safety of Unit 1 seismic Category I structures and has proposed to construct a berm around the Unit 2 excavation pit (letters, April 10, June 22, and August 9, 1984) to control the surface runoff. The hydrological aspects of this problem are evaluated in Section 2.4 of SSER 1. The two geotechnical issues resulting from this open excavation include: (1) stability of the Unit 2 excavation slopes, and (2) sliding stability of the service water tunnel.

2.5.5.1 Stability of Permanent Slopes

Stability of Unit 2 Excavation Slopes

FSAR Figure 2.5-72a shows a plan view of the Unit 2 excavation and the adjoining Unit 1 structures. The north, west, and south slopes of the excavation are cut slopes of in situ soil; the east slope which adjoins Unit 1 structures is formed by placement of compacted backfill materials. Both the cut and the fill slopes are at slopes of 2.4 horizontal to 1 vertical (2.4H:1V) configuration. FSAR Figures 2.5-72b and 2.5.72c, respectively, show the typical cross-sections and foundation conditions of these slopes. The soil stratigraphy and design parameters shown in these figures are reasonable and consistent with the staff's evaluation presented in the SER. The applicant's evaluation on stability for both the cut and fill slopes is presented in letters dated April 10 and June 22, 1984.

A letter dated June 22, 1984 presents the applicant's evaluation of the level of water that would collect in the Unit 2 excavation for various design-basis

events. These water levels are shown in Table 2.1 of this supplement and were conservatively considered in the completed slope stability studies.

Normal groundwater level at the site is at el 57.0 ft. Because the level of the water collected in Unit 2 excavation is higher (see Table 2.1) than the groundwater level at the site, water seeps into the slope. For analysis purposes, the applicant assumed a horizontal groundwater level commensurate with the pond level rather than the actual phreatic surface. This is a conservative assumption because the upper phreatic surface normally will develop a gradient. The subsequent stability analysis of the Unit 2 excavation is thereby conservative. Among the three design-basis conditions analyzed and listed in Table 2.1, the safe shutdown earthquake (SSE) with a 25-year storm was the most severe loading condition for slope stability as discussed below.

In the stability analysis of the cut slope (FSAR Fig. 2.5-72b), the applicant has considered the effects of both the berm to be constructed and the live loads of traffic on adjacent roadways. The top of the berm elevation was based on the operating basis earthquake (OBE) + ½ probable maximum precipitation (PMP) condition because it resulted in a higher required berm elevation than the SSE with coincident 25-year storm. (See Table 2.1.) Two types of potential slope failure modes were analyzed: (1) a massive sliding wedge failure that would connect the West Creek with Unit 2 excavation and (2) a shallow slip circle failure of the slope into the Unit 2 excavation.

Because of the in situ soil stratigraphy that consists of localized loose sand layers, a sliding-wedge method of stability analysis was performed for the first failure mode. The pseudostatic approach was used to consider the effects of the SSE. The sand with gravelly sand stratum (shown as type B soil in FSAR Fig. 2.5-72b) has occasional pockets of loose sand between el 40 and 59 ft (letter, June 22, 1984). Although this layer as a whole was considered to be nonliquefiable (NUREG-0989; letter, June 22, 1984), the impact of reduced shear strength in these localized inclusions of loose sand under SSE loading was considered in the stability analysis by assigning lower shear strength for this cohesionless material. The angle of internal friction was varied between 10° and 35° in a parametric study (letter, June 22, 1984).

The Morgenstern-Price method of analysis was performed using computers and the minimum factor of safety against a deep-seated, wedge-type, sliding failure is 1.30 for the lowest friction angle of 10° as shown in Table 2.2 of this supplement and FSAR Figure 2.5-72b.

The shallow slip circle failure of the cut slopes in sand and clayey sand (shown as type A soil in FSAR Fig. 2.5-72d) was investigated using the psuedostatic approach to consider the effects of SSE. The simplified Bishop method of analysis was performed and Table 2.2 shows the minimum factor of safety against a shallow slip circle failure. The analysis indicates that there may be local sloughing during an SSE but the slopes are stable during static condition. The applicant has indicated that sloughing or localized surficial failure of the cut slope during the SSE will not affect the safety of Unit 1. There are no safety-related components at the bottom of the Unit 2 excavation. However, if the berm were to fail during an SSE event, the applicant has committed to restore the berm to prevent surface runoff from entering into the excavation. This restoration commitment for the berm is acceptable to the staff and it

should also include restoration of Unit 2 excavation slopes around the Unit 1 standby service water tower (SSWT).

FSAR Figure 2.5-72c presents a typical cross-section of the backfill slope on the east side of the Unit 2 excavation. Both the OBE and SSE were considered in the pseudostatic analysis performed using computer-assisted simplified (slip circle) Bishop method. The minimum factors of safety against a shallow slip circle failure are shown in Table 2.2.

The results of the stability analyses presented show that both the in situ slope and the backfill slopes are generally safe against failure during the OBE and SSE. However, the factor of safety against a shallow or surficial failure of the slopes is marginal for the SSE condition. These results include the conservative assumption that the water in both the excavation pit and in the ground behind the slope are at the same level. Even if the slope fails, there is no safety-related item in the Unit 2 excavation that would affect the safety of Unit 1. The applicant has committed to maintain the berm to fulfill its function of diverting surface runoff away from the Unit 2 excavation.

On the basis of a review of the stability analysis presented by the applicant, the staff concludes that the Unit 2 excavation slopes are not detrimental to the safety of Unit 1 structures and the stability of the slopes meets the safety requirements in accordance with 10 CFR 50, Appendix A. On the basis of the staff evaluation presented in this supplement, the confirmatory issue on the stability of Unit 2 excavation slopes (Confirmatory Item 3) is now resolved. The applicant should, however, ensure that the proposed berm around the excavation and the slopes around Unit 1 standby service water tower are maintained to enable it to fulfill its safety function as committed to by the applicant in the letter dated June 22, 1984.

2.5.5.2 Stability of Temporary Slopes

<u>Stability of the Service Water Tunnel (G Tunnel)</u>

Figure 2.1 of this supplement shows a plan and cross-section of the service water tunnel (G tunnel). This tunnel starts from the F tunnel at the west end of the Unit 1 fuel building, runs past the Unit 1 standby service water tower, and terminates near the Unit 2 fuel building. The G tunnel is a reinforced concrete box-type structure that was originally intended to be completely buried underground. However, it was decided to cancel Unit 2 and not to backfill the excavation pit above el 66 ft. Therefore, the G tunnel remains partly buried at its west end with the backfill on the north side of the tunnel 28 ft higher than that on the south side as seen in Figure 2.1. Unbalanced soil loading on the G tunnel results from the applicant's decision not to completely backfill around it. Thus, the applicant has performed a stability analysis of the G tunnel using the following assumptions:

(1) The driving forces for the sliding and overturning analyses include the dynamic soil and water pressures in addition to the earthquake-induced inertia forces of the structure.

(2) The resisting forces are: (a) the base friction, wall friction, and soil pressures, where appropriate, in the case of sliding, and (b) the dead weight of the structure and soil pressures, where appropriate, in the case of overturning.

(3) The internal angle of friction for the compacted cohesionless backfill (sand) is 36°.

(4) The coefficient of friction between soil and concrete poured on compacted fill is taken as 0.55 for sliding analysis.

(5) Since the backfill is placed to the same elevation on both sides of the G tunnel at the east end, at-rest earth pressures are assumed to act there. Because of the difference in backfill elevations toward the west end of the tunnel, sufficient movement of the tunnel is assumed to occur to reduce the driving soil pressure from at-rest condition to a state that approaches active earth pressure at the west end. In the stability analysis of the G tunnel, a lateral earth pressure coefficient of $K_o = 0.45$ is used only for 100 ft at the east end of the tunnel and a coefficient of $K_a = 0.35$ for the remaining length on the north side of the G tunnel. On the south side of the tunnel a coefficient of $K_o = 0.45$ is used throughout the length of the tunnel.

Some of the above assumptions are given in Revision 2 of the applicant's calculation G(c)-185. The staff is satisfied that the above design assumptions satisfactorily represent the existing conditions. The applicant's stability analysis results (shown in FSAR Table 2.5-16) indicate that the minimum factors of safety against sliding and overturning occur under SSE condition and the factors are 1.7 and 1.8, respectively. These results are acceptable to the staff.

On the basis of a review of the applicant's analysis of the stability of the service water tunnel (G tunnel) against sliding and overturning, the staff finds the margins of safety for the stability of the G tunnel to be adequate and acceptable. The applicant will be asked to revise the FSAR to incorporate the design assumptions that were furnished through detailed calculations.

Table 2.1 Water levels in Unit 2 excavation*

Design-basis conditions	Assuming no seepage from Unit 2 excavation, el in ft	Allowing for seepage from ponding in Unit 2 excavation, el in ft	Water level used in stability analysis of slopes, el in ft
Static + PMP	78.1	68.3	80.0
OBE + ½ PMP	69.6	70.0	73.0
SSE + 25-yr storm	67.2	67.2	68.7

*Letter from applicant, June 22, 1984.

**For the 25-year storm condition the resulting water level does not require a berm nor would significant seepage be anticipated.

Table 2.2 Minimum factors of safety for Unit 2 excavation slopes*

Case analyzed	Static	OBE	SSE
1. North, west, and south slopes - cut slopes			
· Deep-seated wedge sliding failure (west slope only)	?	?	1.30**
· Shallow slip circle failure	1.75	1.50	1.33**
2. East slope - fill slope			
· Shallow slip circle failure	1.51	1.21	1.19†

*Letter from applicant, June 22, 1984.

**Deep-seated sliding failure mode was considered only for SSE since that alone may produce partial liquefaction of the loose sands and cause such failure.

†These factors of safety are obtained with friction angle of 35°. Lower safety factors using the infinite slope method do result and would indicate that minor surficial sloughing can occur at the face of the slope.

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, EQUIPMENT, AND COMPONENTS

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

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

In Section 3.6.2 of the River Bend SER (NUREG-0989, May 1984), the staff identified a confirmatory issue regarding documenting in the FSAR the failure modes analysis for pipe breaks. In Amendments 15, 16, and 17 to Appendix 3C.2 of the FSAR, the applicant has provided the results of its failure mode analysis. Appendix 3C.2 provides a discussion of the high-energy pipe breaks and summarizes the effects of pipe whip and jet impingment loadings on safety-related structures, systems, and components. The staff has reviewed the methodology used by the applicant to postulate break locations. The applicant has postulated full break opening areas and no mechanistic approaches were used to reduce break areas. On the basis of the staff review of the failure modes and analyses, the staff finds that safety-related systems, structures, and components have been adequately protected from the dynamic effects associated with postulated high-energy pipe breaks. Thus, the staff concludes the confirmatory item regarding pipe failure modes has been acceptably resolved.

3.9 Mechanical Systems and Components

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

3.9.2.4 Dynamic System Analysis of Reactor Internals Under Faulted Conditions

In Section 3.9.2.4 of the River Bend SER, the staff identified a confirmatory item (Confirmatory Item 5) regarding the documentation in the FSAR of the results of LOCA and SSE analyses for the reactor internals and unbroken loops of the reactor coolant pressure boundary. In a letter dated January 31, 1985, the applicant provided the results of its analyses including the effects of annulus pressurization (AP). Subsequently, the analyses results were documented in FSAR Amendment 16. The staff review finds the results of the analyses satisfies the staff acceptance criteria for the load combinations and stress limits of ASME Code Class 1, 2, and 3 components, component supports, and core-support structures. Thus, the staff concludes that the confirmatory issue regarding the documentation of the LOCA and SSE results for the reactor internals and unbroken loops of rector coolant pressure boundary has been acceptably resolved and Confirmatory Item 5 is considered closed.

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

3.9.3.3 Component Supports

The staff identified a confirmatory item (Confirmatory Item 7) in Section 3.9.3.3 of the River Bend SER regarding the justification for the applicant's position

classifying restraint of piping thermal expansion and relative building displacement stresses as secondary stresses for pipe supports. The applicant provided its response in a letter dated December 21, 1984.

The staff's position with respect to pipe stresses in analyses is that piping thermal stress is treated as a secondary stress. Piping thermal stress is the stress that occurs from restraining the free-end deflection of piping that occurs when temperature increases or decreases. Piping thermal stress is characterized as a secondary stress whether the piping is analyzed by Article 3200 of Subsection NB of Section III of the Code of the American Society of Mechanical Engineers (ASME Code) or by the more simplified and generally used approach of Article NB/NC/NC 3600 of the ASME Code. However, within the limits of reinforcement for Class 1, 2, or 3 vessel nozzles (nozzle-piping transition), restraint of free-end displacement of the attached pipe is considered a primary stress by the Code and the staff concurs in this treatment.

For piping and the pipe-nozzle transition region of a component such as a vessel, the staff has accepted and uses Section III of the ASME Code to characterize the stress which results from the restraint of free-end displacement of piping as primary for nozzles within the area of reinforcement, or as secondary for piping.

Before Subsection NF was issued in 1973, the Code of the American Society of Steel Construction (AISC Code) (Manual of Steel Construction) was used exclusively for support design with the exception of component standard supports. Even now the AISC Code continues to be used for the design of either a portion, or the complete structural load path, of a piping and component support. The AISC Code does not characterize loads as primary or secondary. All loads including those caused by piping thermal expansion are evaluated. When Subsection NF of the Code was first issued in 1973 and then in the 1974, 1977, and 1980 editions of the Code, the staff did not categorically accept the characterization of restraint of piping thermal expansion as a secondary load for support design. Secondary loads, including restraint of free-end displacements from piping thermal expansion and seismic differential building movements, are accounted for in the normal and upset conditions, but were not required to be evaluated for the emergency and faulted conditions by ASME in the above-mentioned versions of Subsection NF, based on the assumption that their effect is usually small. Thermal stresses or other "secondary" effects are not explicitly discussed in the AISC design instructions. However, items meeting the AISC specification must be designed so that stresses which result from all sources are at least within specified allowable values. Unless those loads are evaluated, or their effects are otherwise limited, such as by stipulating a maximum value for support strain, there is no assurance that the support will not fail because of gross plastic deformation or that the deformation will not affect the operability of supported components. To disregard such effects simply because a standard allows the practice is not considered acceptable for a safety system.

Subsection NF in the 1973 edition of the AISC Code, and in all later editions, does not require the evaluation of stresses that result from the restraint of thermal expansion of the support itself. The staff has accepted this provision, requiring an evaluation only in those unusual cases where long-constrained support lengths subject to large temperature changes might collapse or otherwise be appreciably stressed.

For the River Bend facility, the applicant performed a comparison study using the above-described staff position to assess the effect of classifying constraint of thermal expansion and related seismic building displacement stresses as primary stresses on existing pipe support designs.

The applicant selected 250 pipe supports from eight Category I piping systems. These eight piping systems were selected because of their high operating temperatures and seismic building displacements. The pipe sizes varied between 2-inch nominal pipe size (NPS) and 24-inch NPS. The results of the study showed that redefining constraint of thermal expansion and seismic building displacement stresses as primary stresses increased the pipe support stresses; the structural integrity of the designs was not compromised and physical modification of the designs was not required. The designs were evaluated to the allowable stresses of the 1974 ASME Code (including the Summer 1974 Addendum) which is the current River Bend licensing commitment.

On the basis of the results of the applicant's study, the staff concludes that the design methodology used for the River Bend component supports satisfies the staff position described above and, thus, the portion of the confirmatory item dealing with pipe failure modes (Confirmatory Item 7) is considered closed.

3.9.6 Inservice Testing of Pumps and Valves

The applicant had not submitted an inservice testing (IST) program for pumps and valves as of the issue of the SER. Thus, the SER stated that the resolution of this issue would be addressed in an SER supplement. By a letter dated November 5, 1984, the applicant submitted an IST program. By letters dated May 16, 1985, and May 30, 1985, the applicant clarified the status of the program and amended the program, respectively.

The staff has not completed a detailed review of the River Bend IST program. A preliminary review was completed and it was found 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 at this time would, in the staff's 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)(6)(i), the relief that the applicant has requested from the pump and valve testing requirements of the 1980 edition of ASME Code Section XI through Winter 1981 addenda should be granted for a period of no longer than 2 years from the date of issue of the operating license or until the detailed review has been completed, whichever comes first. If the review results in additional testing requirements, the applicant will be required to comply with them.

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

3.10.1 Seismic and Dynamic Qualification

3.10.1.1 Introduction

As part of the review of the applicant's Final Safety Analysis Report (FSAR) Sections 3.7.3A, 3.7.3B, 3.9.2A, 3.9.2B, 3.10A, and 3.10B, an evaluation is made of the applicant's program for seismic and dynamic qualification of

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

Guidance for the evaluation is provided by the Standard Review Plan (SRP) Section 3.10, and its ancillary documents, Regulatory Guides (RGs) 1.61, 1.89, 1.92, and 1.100; NUREG-0484; and Institute of Electrical and Electronics Engineers (IEEE) Stds. 344-1975 and 323-1974. These documents define acceptable methodologies for the seismic qualification of equipment. Conformance with these criteria is required to satisfy the applicable portions of: General Design Criteria (GDC) 1, 2, 4, 14, and 30 (Appendix A to 10 CFR 50), Appendix B to 10 CFR 50, and Appendix A to 10 CFR 100. The program is evaluated by a Seismic Qualification Review Team (SQRT) which consists of staff engineers and engineers from the Brookhaven National Laboratory (BNL, Long Island, New York).

3.10.1.2 Discussion

The SQRT has reviewed the equipment seismic and dynamic qualification information contained in FSAR Sections 3.7.3A, 3.7.3B, 3.9.2A, 3.9.2B, 3.10A, and 3.10B and visited the plant site from October 29 through November 2, 1984. The purpose was to determine the extent to which the qualification of equipment, as installed at River Bend, meets the criteria described above. A representative sample of safety-related electrical and mechanical equipment as well as instrumentation, included in both nuclear steam supply system (NSSS) and balance of plant (BOP) scopes, was selected for the audit. Table 3.1 identifies the equipment audited. The plant-site visit consisted of field observation of the actual, final equipment configuration and its installation. This was followed by a review of the corresponding qualification document. The field installation of the equipment was inspected in order to verify and validate equipment modeling employed in the qualification program. During the audit the applicant presented details of the qualification and in-service inspection program.

3.10.1.3 Summary

On the basis of the observation of the field installation, review of the qualification documents, and responses provided by the applicant to SQRT's questions during the audit, the applicant's seismic and dynamic qualification program, subject to generic findings discussed in Section 3.10.1.4, was found to be defined and implemented. The equipment-specific findings as a result of the SQRT audit are identified in Table 3.1 and the generic comments are listed in the following section. Upon satisfactory resolution of these specific findings and generic comments, the seismic and dynamic qualification of safety-related equipment at the River Bend Station, Unit 1, will meet the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendices A and B to 10 CFR 50 and Appendix A to 10 CFR 100.

3.10.1.4 Confirmatory Items

The satisfactory resolution of the specific findings identified in Table 3.1 and in the generic comments listed below, is required before the staff can accept the applicant's seismic qualification program for equipment:

(1) Each equipment qualification document package contained summary statements and overall conclusions. The conclusion for each package was that the equipment was fully qualified. However, in many instances it was observed that evidence necessary to reach the state of complete qualification was unavailable. More recent documentation packages were incomplete and appeared to be put together without adequate checking after the selection of equipment was transmitted to the applicant. Therefore, the applicant is to develop a more systematic program to perform the acceptance review of all safety-related equipment.

(2) Where the qualification document package identifies a need for equipment modification, the applicant is to develop a systematic program to include in the qualification package either a statement indicating implementation of the modification or justification for not implementing the modification.

(3) In many cases, the equipment qualification report identified parts with a limited life. Such equipment could be located in either a mild or a harsh environment. The applicant is to develop a systematic procedure for identifying limited-life parts and to ensure their replacement at appropriate intervals during the acceptance review of equipment.

(4) Some pieces of equipment were incorrectly or improperly installed. The applicant is to develop a procedure to check proper mounting of all safety-related equipment consistent with the qualification mounting configuration.

(5) The enclosure panel for many pieces of equipment was partially removed or screws were loose, reportedly to facilitate preoperational testing. The applicant is to develop a procedure to ensure that such equipment is returned to the qualified status.

(6) Upon completion of as-built piping analysis for all pipe-mounted safety-related equipment, the applicant must confirm that the g values used for qualification of this equipment was not lower than the g values obtained from the as-built piping analysis.

(7) The qualification of those pieces of equipment which were originally qualified to meet IEEE Std. 344-1971, should be identified and upgraded to meet the requirements of IEEE Std. 344-1975, as applicable.

(8) Upon completion of the on-going qualification process, the applicant must confirm that all safety-related equipment has been qualified.

3.10.2 Pump and Valve Operability

3.10.2.1 Introduction

To ensure that an applicant has developed and implemented a program regarding the operability qualification of safety-related pumps and valves, the staff performs a two-step audit. The first step is a review of FSAR Section 3.9.3.2 for the description of the applicant's pump and valve operability assurance program. The information provided in the FSAR, however, is general in nature and not sufficient by itself to provide confidence in the adequacy of the licensee's overall program for pump and valve operability qualification. To

provide this confidence, the Pump and Valve Operability Review Team (PVORT), consisting of staff from Brookhaven National Laboratory (BNL) and the NRC, conducts an onsite audit of a small representative sample of safety-related pumps and valves and supporting documentation.

The criteria by which the audit is performed are described in SRP Section 3.10 entitled, "Seismic and Dynamic Qualification of Mechanical and Electrical Equipment." Conformance with SRP 3.10 is required in order to satisfy the applicable portions of General Design Criteria (GDC) 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50 and Appendix B to 10 CFR 50.

3.10.2.2 Discussion

In performing the first step of the audit, the staff reviewed FSAR Section 3.9.3.2. The onsite audit, or second step, was performed by the PVORT during the week of October 29, 1984. The purpose of this two-step review process is to determine the extent to which the applicant meets the criteria of SRP Section 3.10. A sample of three NSSS and seven BOP components was selected to be audited.

The onsite audit includes a plant inspection of the as-built configuration and installation of the equipment, a review of the normal, accident, and postaccident conditions under which the equipment and systems must operate, the fluid dynamic loads, and a review of the qualification documentation (status reports, test reports, analysis specifications, surveillance programs, and long-term operability program(s), etc.).

Table 3.2 of this supplement identifies the equipment audited and the findings that remained open as a result of the audit.

3.10.2.3 Summary

On the basis of the observation of the field installation, review of the qualification documents, and responses provided by the applicant to PVORT's questions during the audit, the applicant's pump and valve operability qualification program, subject to generic findings discussed in Section 3.10.2.4 below, has been found to be defined and being implemented. The equipment-specific findings that resulted from the PVORT audit are identified in Table 3.2 and the generic comments are listed below. Upon satisfactory resolution of these specific and generic comments, the seismic and dynamic qualification of safety-related equipment at the River Bend Station, Unit 1, will meet the applicable portions of GDC 1, 2, 4, 14 and 30 (Appendix A to 10 CFR 50); Appendix B to 10 CFR 50; and Appendix A to 10 CFR 100.

3.10.2.4 Generic

The specific findings in Table 3.2 and the generic concerns listed below must be resolved before the staff accepts the applicant's pump and valve operability qualification program.

(1) In many instances, evidence of complete qualification was unavailable. More recent documentation packages were incomplete and appeared to have been put together without checking. The PVORT long forms contained

numerous inconsistencies ranging from inconsistent serial numbers, capability, and qualification information on the actual equipment. The applicant is to develop a more systematic program to perform the acceptance review of safety-related pumps and valves.

(2) During the acceptance review of equipment, a procedure should be developed to identify limited life parts and ensure their replacement at appropriate intervals.

(3) Procedures should be established to return tested equipment to its qualified status.

(4) Components were found to be incorrectly or improperly installed. Procedures should be established verifying equipment installation requirements and qualification.

(5) All pumps and valves important to safety must have their required preoperational tests completed before fuel load.

(6) All pumps and valves important to safety must be qualified before fuel load.

(7) The applicant shall confirm that new loads resulting from loss-of-coolant accident (LOCA) or analysis of as-built conditions applicable to pumps and valves important to safety do not exceed those loads originally used to qualify the equipment.

Table 3.1 SQRT findings on seismic and dynamic qualification

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status	Remarks
NSSS-1	1C11-ACTD001	Hydraulic control unit: Assembly consists of N_2 cylinder, water accumulator, and various valves.	Translates scram signal into hydraulic energy to insert the control rod drive and allow its return flow to discharge through the exhaust valve.	The additional brace used during qualification test of the equipment was missing from the installed unit.	Pending	Open	
NSSS-2	H13-P680	Plant control console: A U-shaped monitoring benchboard.	Supports instruments which are used to monitor and control the safe operation and shutdown of the plant.	The dynamic similarity between the tested specimen and the River Bend console was not established. The test mounting was not documented in the test report. For components qualification, the capability g-values were not defined and demonstrated to envelop the RRS over the entire frequency range.	Pending	Open	
NSSS-3	C61-P001	Remote shutdown vertical board	Provides redundant means for safe shutdown of the plant.	The installation condition of being next to another cabinet and the wall was not addressed in the qualification.	Pending	Open	
NSSS-4	E12-C002A,C	RHR pump and motor	Assembly is required to pump water in the suppression pool during pool cooling modes and LPCI vessel injection modes.			Qualified	
NSSS-5	H13-P601	Reactor core cooling bench board: A monitoring panel.	Contains instruments that are used for manual control for accident mitigation of the emergency core cooling system.	Dynamic similarity between the tested specimen and the River Bend unit was not established. Test mounting was not completely documented in the test report. For component qualification, the capability g-values were not defined and demonstrated to envelop to required response spectra over the entire frequency range.	Pending	Open	

Table 3.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status	Remarks
				Qualification of some devices below 5 Hz was missing. Controller and recorder units were sliding during tests. It could not be verified from documentation presented whether River Bend panel contains these devices. Site inspection revealed the following: One unistrut was loose. GE ERIS terminals were very flexible.			
NSSS-6	H13-P670	Neutron/process radiation monitoring system	Provides information about power levels and power distribution in the reactor, and is tied to a trip system (reactor protection system).	The cabinet was installed with 1/2"-diameter bolts although the specimen was tested with 5/8"-diameter bolts.	Pending	Open	
NSSS-7	H22-P041,42	Main steam flow local panel	Supports Class 1E devices.	Transmitters were not environmentally aged before seismic testing. Transmitter output variation detected during testing was apparently due to incomplete instruction provided by GE to testing engineers regarding calibration. GSU/GE is to confirm that River Bend installation engineers have received the complete instruction and the transmitters are properly calibrated.	Pending	Open	
NSSS-8	B21-F028B	Main steam isolation valve	Isolates the steam line upon demand.	Adequacy of the valve body was not demonstrated. GSU is to confirm compliance with GE's recommendation regarding the following required for qualification:	Pending	Open	

Table 3.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status	Remarks
				Bracket modification for limit switch. Elimination of junction box. The source of River Bend -specific RRS was not presented during the audit.			
BOP-1	1CCP*MOV138	10" motor-operated valve	Is required to isolate the containment and to intercept the water flow of the reactor plant component cooling water system (RPCCW) to the nonregenerative heat exchanger.			Qualified	
BOP-2	1RCP*TCA03	Termination cabinets	Are required at penetrations to contain the wiring used in instrumentation monitoring and control of equipment used in various safety-related functions.			Qualified	
BOP-3	1EHS*MCC	Motor control center: A two-bay rectangular cab'net containing st rters, circuit breakers, switches, terminal blocks, etc.	Is required to provide Class 1E power distribution.	Qualification of devices apparently covered by Gould reports R-STS-10,31 and analysis was not available for review. Test mounting was not documented. It is not clear from test report whether the MCC was tested for 5 OBE and 1 SSE for both the energized and deenergized conditions. Supplemental evaluation report for HE 4-3 circuit breakers was not part of the qualification documentation package.	Pending	Open	

Table 3.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status	Remarks
BOP-4	1E12*PC003	Centrifugal fill pump: A pump/motor assembly.	Maintains the RHR system piping filled and ready for main RHR pump startup.	The site inspection revealed the following deficiencies: The shim stack was loose. One nut in the seal housing was loose and another was missing. The motor nameplate was missing.	Pending	Open	
BOP-5	1HVC*ACU1B	Control building air conditioning unit	Maintains the control building at design temperature and humidity.			Qualified	
BOP-6	1HVR*AOD10A	Air-operated damper: It is duct mounted and supported from the ceiling.	Operates only during LOCA when it bypasses the air to the standby gas treatment building.			Qualified	
BOP-7	1LSV*C3A	Leakage air system compressor: A single rotary compressor with electric motor drive.	Provides pressurized air to containment isolation valves to prevent release of fission products after LOCA.			Qualified	
BOP-8	1SCM*XRC14	Transformer	Furnishes power to various Class 1E instruments as part of the uninterrupted power supply system.	Dynamic similarity between the tested specimen and the River Bend transformer was not established. Test mounting was not completely documented in the test report. Test anomalies were mentioned, but neither described nor justified in the test report. Site inspection revealed the following: There was no contact between the base plate and concrete in most places. Side panels were loose. Base plate was not addressed in the qualification documents presented.	Pending	Open	

Table 3.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status	Remarks
BOP-9	1EJS*LDC1A	Load centers	Are required to furnish power distribution to HVAC systems in the control and diesel generator building and also to Class 1E motor control centers.	Only a summary of test report was available. The original Wyle Test Report is needed for review and documentation.	Pending	Open	
BOP-10	1SWP*P2B	Standby service water pump: An electrically driven vertical turbine pump.	Provides cooling water for safety-related equipment when normal service water is lost.	Torsional frequency of assembly needs to be computed and compared to motor's operational speed. Operability of pump under seismic load needs to be ensured.	Pending	Open	

Table 3.2 PVORT findings on operability qualification of pumps and valves

Plant I.D. No.	Description	Safety function	Findings/resolution	Status	Remarks
E22-F015	20" motor operated gate valve (NSSS)	Opens in response to either a suppression pool high-level signal or a low-condensate, tank-level, containment isolation.	Operability of the valve was established using analysis only. A test program is presently being performed and a similar analysis with a similar valve which was tested will be submitted as demonstration of operability and qualification.	Open	
ISWP-P2A	Standby service water pump (BOP)	Provides cooling water for safety-related equipment if normal service water is lost.	Clarify vibration acceptance criteria (displacement velocity)?	Open	
			Coupling runout value (driven member) is inconsistent with alignment requirement.	Open	
			Pump weight incorrect on PVORT sheets.	Open	
			Final qualification subject to compiiance with endurance testing recommended in IE Bulletin 83-05.	Open	
B33-F060A	20" flow control valve (NSSS)	Maintains pressure boundary integrity.	Satisfactory.	Closed	

Table 3.2 (Continued)

Plant I.D. No.	Description	Safety function	Findings/resolution	Status	Remarks
1E12-MOVF021	14" motor-operated globe valve (BOP)	Containment isolation.	Have stem leakoff requirements been met? N&D No. 6189 motor starter housing welded to motor flange. Have possible effects of welding on valve flange and valve shaft assembly been considered? Dates of issue on qualified documents very recent (i.e., [illegible]-7003 "Operability Test Procedure" is dated 11/2/84 which was the exit meeting date). Completeness and approval required.	Open	
1HVC-MOV1B	24" motor-operated butterfly valve (BOP)	Isolates main control room during LOCA.	Actuator is serialized (260880); adapter plant is also serialized (260953). PVORT form picked up the adapter serial no. in place of the actuator no. Clarification required.	Open	
1CCP-MOV138	10" motor-operated gate valve (BOP)	Outboard containment isolation valve.	Valve has serial no. 809 (1980) on "N" stamp tag. Manufacturer's nameplate	Open	

Table 3.2 (Continued)

Plant I.D. No.	Description	Safety function	Findings/resolution	Status	Remarks
1CCP-MOV138 (Contd)	10" motor-operated gate valve (BOP)	Outboard containment isolation valve.	serial no. is 1413-2. PVORT form lists valve serial no. as 809(1980). Inspection and test record form lists serial no. as 1413. Clarification required.		
			Stroke time requirements vary from 30 sec (spec sheet) to 22 sec (inspection and test record) to 20 sec (PVORT form). Clarification required.	Open	
			Have stem leakoff requirements been provided?	Open	
			Have space heaters been removed?	Open	
			Rev. 2 to MOV Checkout Procedure 1, 1-G-EE-18, initiated due to excessive torque values in Rev 1. Comparing Revs 1 and 2, the torque valves appear to be the same.	Open	
B21-AOVF32A (BOP)	20" check valve	Containment isolation and reactor coolant pressure boundary.	Satisfactory.	Closed	

Table 3.2 (Continued)

Plant I.D. No.	Description	Safety function	Findings/resolution	Status	Remarks
E33-SOV14	2" solenoid-operated globe valve (BOP)	Provides initial pressurization of main steam positive leak control system.	Valve installation contradicts note 18 of FSAR Fig. 6.7-1, qualification documentation and manufacture recommendations.	Open	
			If the working fluid (air) provides opening force, what is the minimum air pressure required to open the valves?	Open	
			Are the forces delivered by the spring capable of closing the valve against the loads of the working fluid?	Open	
			What assurance is there that the delivered air quality is in agreement with the manufacturer's requirements?		
			List tests performed by GSU to date or to be performed in the future.	Open	
			How to or will GSU track manufacturer's recommendations regarding maintainability of components subject to aging?		

Table 3.2 (Continued)

Plant I.D. No.	Description	Safety function	Findings/resolution	Status	Remarks
E12-C002C	RHR pump (NSSS)	Supplies water to the core in the event of an accident.	How is pump performance (curves, vibration levels, bearing temp., etc) established without the use of manufacturer's data/acceptance criteria?	Open	
		Suppression pool cooling.	Discharge pressure transmitter has a reject tag and as-built acceptance tag. Clarify difference and the reason for the reject tag and the action taken.	Open	
			Serial no. on motor qualification documentation and long form disagree.	Open	
			Clarify the differences between GE specification 21A3504, Rev. 1 and 21A3504BV, Rev. 0 (e.g., removal of IEEE standards; is this component built to IEEE, if not justify why.	Open	
			Clarify how GSU will or has identified parts sensitive to aging mechanism and how they will be tracked.		

Table 3.2 (Continued)

Plant I.D. No.	Description	Safety function	Findings/resolution	Status	Remarks
E12PC003	RHR subsystem fill pump (BOP)	Maintains RHR system piping filled and ready for RHR pump startup.	The specification specifies demineralized water on data sheet while the pump actually takes suction from suppression pool. What effect does this have on operability, performance, life of wear rings, bearings, seals, impellers, etc.? At reduced voltages what is the capability of the pump/motor, and does it meet the requirements of the system?	Open	

4 REACTOR

4.2 Fuel System Design

4.2.3 Design Evaluation

4.2.3.2 Fuel Rod Failure Evaluation

(8) Fuel Rod Mechanical Fracturing

The applicant has submitted for staff review a plant-specific analysis (letter, November 30, 1984) using the approved methodology described in the General Electric Co. (GE) report NEDE-21175-3. The staff finds these results to be acceptable and the issue of fuel rod mechanical fracturing (Confirmatory Item 8) is resolved. Since the mechanical fracturing analysis is usually done as a part of the seismic-and-LOCA loads analysis, further discussion can be found in Section 4.2.3.3(4).

4.2.3.3 Fuel Coolability Evaluation

(4) Fuel Assembly Structural Damage From External Forces

The staff approved (Thomas, October 20, 1983) the GE topical report NEDE-21175-3, which describes an analytical method for evaluating seismic-and-LOCA loads. The staff has also reviewed the plant-specific values of liftoff and acceleration (letter, November 30, 1984). The results show that the vertical liftoff is less than the allowable liftoff limit given in NEDE-21175-3, which is referenced by the applicant, and the acceleration is within the evaluation-basis limits, thereby assuring structural integrity and control rod insertability during seismic-and-LOCA events. Therefore, the staff concludes that the confirmatory issue of seismic-and-LOCA loads, is satisfactorily resolved for River Bend.

4.4 Thermal and Hydraulic Design

4.4.4 Thermal-Hydraulic Stability

GE originally proposed a BWR stability design criterion for a decay ratio of less than 0.5. The applicant has calculated that the River Bend Units 1 and 2 core design will exceed this value. In addition, more recent operating and test data from other BWRs have demonstrated the occurrence of limit cycle neutron flux oscillations at natural circulation and several percent above the rated rod line. The oscillations were observable on the average power range monitors (APRMs) and were suppressed with control rod insertion. It was predicted that limit cycle oscillations would occur at the operating conditions tested; however, the characteristics of the observed oscillations were different from those previously observed in other stability tests. Namely, the test data taken showed that some low power range monitor (LPRM) detectors oscillated out of phase with the APRM signal and at an amplitude as great as six times the core average. GE has prepared and released a service information letter, SIL-380, to alert the

...owners to these new data and to recommend actions to avoid and control abnormal neutron flux oscillations.

The staff has reviewed the initial fuel loading of River Bend Units 1 and 2 and finds it to be bounded by GE analyses presented in NEDE-24011. Therefore, this core meets the stability criteria set forth in GDC 10 and 12 and is acceptable on the condition that the Technical Specifications include appropriate limiting conditions for operation and surveillance requirements to address the concerns stated in SIL-380 and to avoid operation in regions of thermal-hydraulic instability. Also, in order to provide additional margin for stability, power operation in natural circulation is prohibited.

Since no analysis has been presented for minimum critical power ratio limits or stability characteristics for single-loop operation, the staff will require Technical Specifications which prohibit single-loop operation. After supporting analyses are provided, single-loop operation may be approved upon submittal of appropriate Technical Specifications to avoid operation in regions of potential thermal-hydraulic instability.

Recent BWR fuel design changes that affect stability include decreasing the rod size and increasing the gap conductance because of prepressurization. As a consequence, the maximum decay ratio for most BWRs increases and becomes larger than 0.5, which is the original GE design criterion for BWR stability. Therefore, GE now proposes a decay ratio of 1.0 for its criterion.

To further evaluate this criterion and other stability criteria, the staff is performing a generic study of the hydrodynamic stability characteristics of light water reactors under normal operation, anticipated transients, and accident conditions. The results of this study will be applied to the staff's review and acceptance of stability analyses and analytical methods now in use by the reactor vendors.

The stability analysis resulted in a maximum decay ratio of 0.98. Since the calculated maximum stability ratio is equal to that of some of the operating plants (for example, Peach Bottom Units 2 and 3 have a decay ratio of 0.98), the staff concludes that the thermal-hydraulic stability result is acceptable for plant operation. However, to provide additional margin for stability, natural circulation under normal operation will be prohibited.

Because no analysis has been presented for minimum critical power ratio (MCPR) limits or stability characteristics for single-loop operation, the staff will require by Technical Specifications that single-loop operation not be permitted until supporting analyses are provided and approved. A licensing condition will be imposed on operation beyond the first cycle. Operation beyond the first cycle is not permitted until a stability analysis is provided and approved for additional cycles of operation.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Containment Functional Design

6.2.1.3/6.2.1.4 Short-Term Pressure Response/Long-Term Response

Repressurization Analysis

In Section 6.2.3 of the SER, the staff stated that it will require the applicant to provide an analysis to show that repressurization of the containment due to all sources of inleakage such as the penetration valve leakage control system (PVLCS) and main steam positive leakage control system (MSPLCS) would not exceed 50% of the containment design pressure during the 30-day period following onset of a LOCA.

In its letter dated January 28, 1985, the applicant stated that the required analysis has been performed and it was determined that a constant 425 scfh inleakage from both the PVLCS and the MSPLCS would meet the above criterion. However, as a safety margin, the applicant has proposed to specify in the plant's Technical Specifications (TS) the allowable containment inleakage from both the PVLCS and MSPLCS to be 340 scfh, i.e., 80% of the acceptable inleakage.

On the basis of its assessment of the applicant's submittal, the staff finds that the TS inleakage will not repressurize the containment to more than 50% of the containment design pressure in a 30-day period. It is, therefore, acceptable.

LOCTVS/CONTEMPT Computer Codes

In the SER, the staff indicated that it would analyze the containment pressure and temperature response using the CONTEMPT/LT-28 computer code to confirm the applicant's analyses. The staff has completed its analyses using the CONTEMPT-4

code and concludes that the peak calculated pressures and temperatures reported in the SER are in reasonable agreement with the values calculated using the CONTEMPT-4 computer code. This favorable comparison confirms the applicant's analyses. In addition, the applicant provided the results of the analyses performed to support the acceptability of the plant's Technical Specifications-allowable initial conditions. On the basis of its review of the applicant's results, the staff concludes that the peak pressure and temperature, in both the drywell and containment, will not exceed their respective design values and therefore, the proposed Technical Specification-allowable initial conditions are acceptable.

6.2.1.5 Reverse Pressurization

See Section 6.2.1.8 of this SSER for compliance with NUREG-0978

6.2.1.6 Subcompartment Pressure analysis

In Section 6.2.1.6 of the SER, the staff stated that it would verify that the calculated differential pressure for the various subcompartments (reactor water cleanup system rooms) will not exceed the design values.

The applicant's subcompartment nodal models of the different subcompartments consider all major flow restrictions. The staff has reviewed the applicant's models and the results of the analyses of the differential pressure. On the basis of a comparison of the results provided by using similar analytical models for similar subcompartment configurations, the staff finds the applicant's analyses of the differential pressures resulting from the design-basis accident to be conservative and, therefore, acceptable.

In addition to the subcompartment differential pressure analyses, the applicant has performed force calculations on the RPV and the RPV shield wall resulting from the asymmetric pressure loads calculated in the subcompartment analysis.

The staff has reviewed the applicant's method of determining forces from the differential pressure results and finds these methods and results acceptable.

6.2.1.7 Steam Bypass of the Suppression Pool

In Section 6.2.1.7 of the SER, the staff indicated that it would report its findings on the acceptability of the proposed 200°F/hour reactor vessel cooldown rate assumed in the applicant's analyses. This rate was considered in demonstrating the plant's suppression pool bypass capability of $A/\sqrt{K}$ of 1.0 ft^2. The applicant informed the staff that the plant emergency operating procedures will call for a 100°F/hour reactor pressure cooldown rate, unless the containment-to-annulus differential pressure exceeds 5 psid in less than 5 minutes. Under these conditions, the operator will be instructed to proceed with a 200°F/hour controlled reactor vessel cooldown. However, in recent discussions with the staff, it was concluded that the plant's operating procedures do not reflect this procedure. To ensure that the plant's operating procedure conforms to the assumptions used in the suppression pool bypass design basis, the applicant provided the following information.

The River Bend Station Emergency Operating Procedures (EOPs) will direct the operator to initiate the automatic depressurization system (ADS) whenever the containment-to-annulus differential pressure reaches 5 psid. This action has been shown by analysis to provide acceptable containment pressures and, therefore, is acceptable.

The NRC staff, however, expressed a concern regarding the use of ADS when the containment-to-annulus differential pressure reaches 5 psid, when shutdown via the normal controlled rate of 100°F/hour might be possible.

The applicant agrees with the staff that ADS may not always be the preferred action. Therefore, the applicant stated that the EOP will be modified before initial criticality after the first refueling outage to provide more definitive information to deal with the steam bypass concern.

6.2.1.8 Pool Dynamics

6.2.1.8.3 Hydrodynamic Load Assessment

Section 6.2.1.8.3 of the SER identified the SRV-related pool dynamic loads an outstanding issue.

The staff has completed its review of the SRV-related pool dynamic loads. The results of this evaluation are summarized below.

Safety/Relief Valve Dynamics

Actuation of the safety/relief valves (SRVs) produces transient loading on components and structures in the suppression pool region. Before actuation, the discharge piping of an SRV line contains atmospheric air and a column of water corresponding to the line's submergence. Following SRV actuation, pressure builds up inside the piping as steam compresses the air in the line.

The resulting high-pressure air bubble that enters the pool oscillates in the pool as it goes through cycles of overexpansion and recompression. The bubble oscillations, resulting from SRV actuation and discharge, cause oscillating pressures throughout the pool, resulting in dynamic loads on the pool's boundaries and submerged structures.

Severe steam condensation vibration phenomena can potentially occur when high-pressure, high-temperature steam is continuously discharged at high mass velocity into the pool, if the pool is at elevated temperatures. These steam-quenching vibrations would result in loads on the pool's boundaries and submerged structures.

The River Bend design utilizes the GE X-quencher device to mitigate pool temperature effects and dynamic forces. In NUREG-0802, "Safety/Relief Valve Quencher Loads: Evaluation for BWR Mark II and Mark III Containments," dated October 1982, the staff set forth the X-quencher generic load specifications and the staff's acceptance criteria. The applicant has performed its evaluation and assessment of the containment design based on these loads.

In Attachment A to FSAR Appendix 6A, the applicant provided a detailed comparison of the River Bend design basis to the GESSAR II methodology. The staff has completed its review of the River Bend load specifications against the generic acceptance criteria and concludes that the SRV pool dynamic loads utilized by the applicant are in conformance with GESSAR II specifications and are, therefore, acceptable.

LOCA-Related Hydrodynamic Load Assessment

The Mark III pool dynamic loads were reviewed at the construction permit (CP) stage for the River Bend Station, Unit 1, and at the preliminary design approval (PDA) stage for GESSAR-238NI. The staff concluded at that time that the information available was sufficient to adequately define the pool dynamic loads for nuclear plants at the CP stage of licensing. Since the issuance of the GESSAR-238NI SER (NUREG-75/110, Dec. 1975), GE has conducted further tests and analyses to confirm and refine the original load definitions. To keep the NRC and Mark III applicants apprised of the current status of these tests, GE issued an Interim Containment Loads Report (22A4365) in April 1978 and several revisions to it before the GESSAR II application was provided to the staff in March 1980. The GESSAR II application if GE's final design approval (FDA) submittal for its standard "nuclear island" design and is to be referenced by the MARK III operating license (OL) applicants. Appendix 3B of the GESSAR II application provides the standard pool dynamic load definitions for Mark III containments, and is the basic document used for review by the staff and its consultants.

The applicant has included Appendix 3B of GESSAR II by reference in Appendix 6A of its FSAR submittal. Except as noted below, the applicant has adhered to all analytical techniques, assumptions, methodologies, and concepts contained in Appendix 3B of GESSAR II. Where plant-unique parameters differ from those of the GE standard plant, River Bend parameters are used.

The staff has completed its review of GE's pool dynamic load definitions and has arrived at a definitive set of hydrodynamic load definitions that can be used by all Mark III containment applicants for operating licenses. The

results of this generic review are documented in NUREG-0978, "Mark III LOCA-Related Hydrodynamic Load Definition." They are applicable to River Bend.

Description of Phenomena

Figure 6.4 of the SER shows the sequence of events occurring during a design-basis accident (DBA) and the potential loading conditions associated with these events. Following onset of a postulated LOCA, the drywell pressure increases because of blowdown of the reactor system. Pressurization of the drywell causes the water initially standing in the vent system to be accelerated into the pool and the vents are cleared of water. During this vent-clearing process, the water leaving the horizontal vents forms jets in the suppression pool and causes water jet impingement loads on the structures within the suppression pool and on the containment wall opposite the vents. During the vent-clearing transient, the drywell is subjected to a pressure differential and the weir wall experiences a vent-clearing reaction force.

Immediately following vent clearing, an air and steam bubble forms at the exit of the vents. The bubble pressure initially is assumed equal to the current drywell pressure. This bubble theoretically transmits a pressure wave through the suppression pool water and results in loading on the suppression pool boundaries and on equipment located in the suppression pool. As the airflow and steamflow from the drywell become established in the vent system, the initial vent exit bubble expands to equalize the suppression pool hydrostatic pressure. Test results from GE's large-scale pressure suppression test facility (PSTF) show that the steam portion of the flow is condensed, but continued injection of drywell air and expansion of the air bubble results in a rise in the surface of the suppression pool. During the early stages of this process, the pool swells in a bulk mode (i.e., a slug of solid water is accelerated upward by the air). Structures close to the pool surface will experience loads as the rising pool surface impacts the lower surface of the structure. In addition to these initial impact loads, these same structures will experience drag loads as water flows past them. Equipment in the suppression pool will also experience drag loads.

After the pool surface has risen approximately 15 feet above the initial pool surface, the thickness of the water ligament has decreased to 2 feet or less and the impact loads are significantly reduced. This phase is referred to as incipient breakthrough (i.e., the ligament begins to break up). To account for possible nonconservatisms in the test facility arrangement, the staff has determined that the breakthrough height should be set at 18 feet above the initial pool surface.

Ligament thickness continues to decrease until complete breakthrough is reached and the air bubble can vent to the containment free space. The breakthrough process results in formation of an air/water froth and, for load definition purposes, is defined to occur at a height of 19 feet above the initial pool surface. The incipient breakthrough height and the height at which froth loads begin, have been set higher than the maximum prediction from test results to ensure conservatism. Continued injection of drywell air into the suppression pool results in a period of froth pool swell. This froth swell impinges on structures it encounters, but the two-phase nature of the fluid results in loads that are much less than the impact loads associated with bulk pool swell.

When the froth reaches the elevation of the floors on which the hydraulic control units for the control rod drives are located (approximately 24 feet above pool level), the froth encounters a flow restriction, which results in approximately 25% of the unrestricted flow area. The froth pool swell experiences a two-phase pressure drop as it is forced to flow through the available open areas. This pressure differential represents a load on both the floor structures and on the adjacent containment and drywell. The result is a discontinuous pressure loading at this elevation.

As drywell air flow through the horizontal vent system decreases, and the air/water suppression pool mixture experiences gravity-induced phase separation, upward movement of pool water stops and the fallback process starts. During this process, floors and other flat structures experience downward loading and the containment wall theoretically can be subjected to a small pressure increase. However, this pressure increase has not been observed experimentally.

The DBA pool-swell transient associated with drywell air venting to the pool typically lasts 3 to 5 seconds. Following this, there is a long period of high steam flow through the vent system; available data indicate that this steam will be entirely condensed in the immediate vicinity of the vent exits. For the DBA reactor blowdown, steam condensation lasts for a period of approximately 1 minute. Potential structural loadings during the steam condensation phase of the accident have been observed, and are included in the containment loading specification.

As the reactor blowdown proceeds, the primary system becomes depleted of high-energy fluid inventory with a corresponding reduction of the steamflow rate to the vent system. This reduced steamflow rate leads to a reduction in the drywell/containment pressure differential which in turn results in sequential recovering of the horizontal vents. Suppression pool recovery of a particular vent row occurs when the vent stagnation differential pressure corresponds to the suppression pool hydrostatic pressure at that row of vents.

Toward the end of the reactor blowdown, the top row of vents is capable of condensing the reduced blowdown flow and the two lower rows will be totally recovered. As the blowdown steamflow further decreases to very low values, the water in the top row of vents start to oscillate back and forth causing what has become known as vent chugging. This action results in dynamic loads on the top vents and on the weir wall opposite the upper row of vents. In addition, an oscillatory pressure loading condition can occur on the drywell and containment walls. Since this phenomenon is steam mass-flux dependent (the chugging threshold appears to be in the range of 10 lb/sec/ft^2), it is present for all break sizes. For smaller breaks, it is the only mode of condensation that the vent system will experience.

Shortly after a postulated pipe rupture, the emergency core cooling system (ECCS) pumps will automatically start up and pump condensate water and/or suppression pool water into the reactor pressure vessel. This water floods the reactor core and the water may start to cascade into the drywell from the break (the time at which this occurs depends upon break size and location). Because the drywell is full of steam at the time of vessel flooding, the sudden introduction of cool water could cause rapid steam condensation and drywell depressurization. When the drywell pressure falls below the containment pressure,

the suppression pool leve, will depress until the horizontal vents are uncovered and air from the containment enters the drywell. Eventually sufficient air will be returned through the vents to stabilize the drywell and containment pressures; however, during this drywell depressurization transient, there could be a period when a significant negative pressure acts on the drywell structure. A conservative negative-load condition, therefore, was specified for the drywell design.

Small breaks, defined as breaks not large enough to automatically depressurize the reactor, do not result in bounding pool dynamic loads except for the chugging loads and thermal loading conditions on the drywell and weir walls. Thermal gradient load definitions are provided for in the design of the walls containing the suppression pool.

Pool Dynamic Load Assessment

(1) Generic Load Definition

The staff's review of the generic LOCA-related pool dynamic load definition was completed early in 1984. The results of this review and the staff's evaluation of the pool dynamic load definitions are documented in NUREG-0978, "Mark III LOCA-Related Hydrodynamic Load Definition," which was published in August 1984. With only a few exceptions, the staff found the load definitions proposed by the General Electric Company in Appendix 3B of GESSAR II to be acceptable. A set of acceptance criteria was developed by the staff to cover those areas where the proposed loads were not satisfactory. These were included as Appendix C to NUREG-0987. A brief description of these acceptance criteria is provided below.

(a) Pool Swell Velocity

Pool swell velocity controls impact and drag loads on the structures between the initial pool surface elevation and the breakthrough elevation. GESSAR II proposes a value of 40 ft/sec at all levations. The staff requires use of an

elevation-dependent value which varies linearly from 0 up to a maximum of 50 ft/sec at elevations greater than or equal to 10 feet above the initial elevation.

(b) Pool Swell Loads on Structures Attached to the Containment Walls

The GESSAR II specification corresponds to steady-state drag at a fixed velocity of 40 ft/sec. The staff's acceptance criteria require this to be modified to reflect the change in pool swell velocity given in item above and the inclusion of impact-type forces when the structure is not immersed prior to pool swell. A detailed procedure for evaluating the impact load is provided in the acceptance criteria.

(c) Bulk Impact on Small Structures

The GESSAR II methodology was found acceptable provided the structures involved satisfied certain limitations related to structural natural frequency, size, and location above the pool. The acceptance criteria require that when any of these limitations are not satisfied, the load specification be reviewed by the staff on a plant-unique basis.

(d) Froth Impact Loads

The GESSAR II methodology was found to be unacceptable. An acceptable alternative was developed by the staff and its consultants and is described in detail in the acceptance criteria. The new method differs from the GESSAR II approach with respect to maximum froth impact pressure, temporal characteristics of the forcing functions, and region of application.

(e) Drag Loads

The GESSAR II methods are found acceptable provided they are modified to account for the change in pool velocity given in item above and provided they correctly account for the structure-wall interaction effect on drag loads.

(f) Loads on Submerged Structures

The GESSAR II methods are acceptable except for computation of acceleration loads on noncylindrical structures and the evaluation of standard drag during the condensation oscillation (CO) phase of the LOCA. The staff requires that the Mark I acceptance criteria as set forth in NUREG-0661 be used to develop these loads.

(g) Impact Loads on Structures Above the Weir Annulus

The GESSAR II methods were found to be acceptable except for radial structures located within 1 foot of the top of the weir wall and all structures located between 0 and 0.25 foot above the weir wall. Detailed procedures for evaluation of the impact loads in these cases are provided in the acceptance criteria.

(2) River Bend Station Plant-Unique Load Evaluation

(a) Applicability of the Generic Load Definition

The staff has examined the information supplied in the FSAR and has concluded that the generic load criteria described in NUREG-0978 are applicable to the River Bend Station. All major structures and components that would experience LOCA-related pool dynamic loads are within the range of applicability of the staff-approved methodology in terms of geometry and relative location in the containment and the suppression pool. The major features of the suppression pool geometry (main vent submergence and vertical spacing, pool radial width, and pool depth) differ slightly from the standard plant dimensions but these differences are not considered significant in terms of their effect on pool dynamic loads. The use of the generic methodology by the applicant to develop the LOCA-related pool dynamic load definition is, therefore, acceptable to the staff.

(b) Plant-Unique Load Definition - Impact Loads on Certain Structures Between the Pool Surface and the Hydraulic Control Unit Floors

The bulk impact load specification in the NRC's acceptance criteria (NUREG-0978) states that the GESSAR II methodology is acceptable, subject to the following limitations:

(i) Targets must have combinations of widths and natural frequences such that Figures 3B.33-1, 2, 3, and 4 of GESSAR II indicate them to be in the "GESSAR conservative" region with respect to the V = 50 ft/sec pool velocity curve,

(ii) There are no structures smaller than 4 feet long,

(iii) There are no structures closer than 6 feet above the pool.

In plant designs where some specific structures may not meet limitations i or iii, the pulse duration must be shortened with an appropriate adjustment to the pressure amplitude. The load specifications for these structures will be reviewed by the staff on a plant-unique basis. To aid the Mark III applicants in this complex issue, the staff had its BNL consultants prepare load specifications for structures that do not meet limitations ii and iii that can, at the option of each Mark III applicant, be used to evaluate these structures.

The River Bend Station structures above the pool satisfy limitation 2.8.i. However, limitations 2.b.ii and 2.b.iii are not satisfied for all structures. The FSAR has utilized a modified version of the Maise criteria (Maise, February 15, 1984) for the design of structures closer than 6 feet from the pool surface and/or shorter than 4 feet in length. These modifications involve first decreasing the impact pressure amplitude by a factor $(V/50)^2$, where V is the slug velocity at the structure elevation, and then increasing it by the factor $0.007/\tau$ where τ is the impact pulse duration determine according to the requirements of Maise.

The Maise criteria do not allow a $(V/50)^2$ reduction in peak pressure amplitude. They do, however, permit a somehwat smaller increase in pressure for impulse durations less than 7 msec; i.e., the requisite increase is not $(0.007/\tau)$ but

0.007 V/50τ. It is not clear how the River Bend version of the Maise criteria evolved, but the overall result is a load specification that utilizes a peak impact pressure amplitude which is a factor V/50 less than that imposed ink Maise's report.

To address the staff's concern relative to this apparent nonconservatism, the applicant supplied additional information to demonstrate the adequacy of their approach in a letter sent to NRC dated June 3, 1985. This information consisted of a comparison between the River Bend design impact pressures on selected structures with those predicted by an alternate method previously approved by the staff. These comparisons demonstrated that the River Bend method yields loads that exceed those derived from the alternate method by margins of 1.25 and greater for radially oriented structures and 2.3 and greater for circumferential targets.

The applicant provided a detailed description of the alternate method in Attachment 1 to the June 3, 1985, letter to the staff. The staff and its consultants have reviewed this methodology and find that it conforms in almost all respects to procedural steps previously approved by the NRC staff in NRC reports NUREG-0487 and NUREG-0661. Two areas of nonconformance have been identified however. These are the use of a triangular impulse to represent the impact load and determination of hydrodynamic mass M_H, for circumferentially oriented structures from Figure 6-9 of GE Report NEDE-13426P. The methods approved by the staff require use of a versed sine representation for impulse shape and determination of M_H from Figure 6-8 of NEDE-13426P for all structures.

Both of the modifications used by the applicant imply a reduction in the derived load. This reduction is estimated to range between 10 and 25% because of the use of a triangular pulse (depending on structural natural frequency) and to be about 60% because of the use of the Figure 6-9 to determine M_H for circumferentially oriented structures. Application of the correct procedures would therefore imply an increase of up to 25% in load for radial targets and a doubling of the load for circumferential targets. Although these increases are substantial, they are still bounded by the margins demonstrated by the comparisons that were

provided in the applicant's letter of June 3, 1985. According, the staff finds this plant-unique load specification acceptable.

Conclusion

The staff has completed its review of the LOCA-related pool dynamic loads for the River Bend Station and finds the load definition used by the applicant conservative and acceptable.

6.2.1.9 Mark III-Related Issues

In a letter dated May 8, 1982, John Humphrey, a former GE engineer, notified Mississippi Power and Light Company (MP&L) of certain safety concerns regarding the Grand Gulf Mark III containment design. The staff met with MP&L, GE, and Mr. Humphrey to determine the character of these concerns and to establish an appropriate program for their resolution. A number of other Mark III plant applicants attended the meeting, including representatives of Gulf States Utilities (GSU) for River Bend Station (RBS).

The staff has reviewed the information supplied by the applicant for the RBS in letters dated February 28, 1984, and January 23, 1985. These letters contain the applicant's responses to all the Humphrey concerns. The details of the staff's review of each of the 66 individual Humphrey concerns (covering 22 major areas) are contained in Appendix K. The staff concludes that all but two major areas (covering 8 individual Humphrey concerns) and a small portion of a third area have been satisfactorily resolved for the River Bend Station.

The two areas for which further information will be required before resolution can be reached are the SRV discharge line sleeve steam condensation load definitions and the RHR heat exchanger relief line load definitions. The third, and minor, area is the effect of encroachments on submerged structure loads. Resolution of this issue is expected to be uncomplicated.

On the basis of the information received to date, regarding the SRV discharge sleeve steam condensation loads, the staff finds that sufficient justification has been provided for power operation up to 5% of related power.

The staff will require that the applicant not use the residual heat removal system in the steam condensing mode pending resolution of the staff's concerns in the second area, the RHR heat exchanger relief line load definitions. The loads from other discharge lines in the suppression pool are not expected to produce bounding load definitions and no restrictions on power operations are needed during the time it takes for the applicant to respond to the confirmatory questions raised by the staff for these lines.

The staff will assess the applicant's responses to its request for additional information, as identified in the report (Appendix K) on these three Humphrey areas, and will report its results in a future supplement to the SER. However, this issue is resolved because the license will be conditioned on the applicant not using the RHR in the steam-condensing mode.

6.2.2 Containment Heat Removal System

See Section 6.2.1.8 of this supplement for discussion on compliance with NUREG-0978.

6.2.3 Secondary Containment Functional Design

In Section 6.2.3 of the SER, the staff indicated that the secondary containment is comprised of the annulus building, the auxiliary building, and the fuel building and completely surrounds the primary containment. It is maintained at a negative pressure during normal plant operation.

Since then, the applicant has proposed to maintain the auxiliary building and fuel building at atmospheric pressure (0.0 psig) and the annulus (shield) building at 3.0 inches of vacuum water gauge (WG).

Assuming the onset of a LOCA along with loss of offsite power, the applicant has performed analyses to determine the length of time it takes to bring the secondary containment building (i.e., the annulus (shield) building, the auxiliary building, and the fuel building) to -0.25 inch WG.

The annulus analysis, assuming the normal operating condition of -3.0 inches WG, inleakage of 2000 ft^3/min, and 38 seconds of delay for the standby gas treatment system (SGTS) to get up to speed, indicates that -0.25 inch WG is attained in 203 seconds. The results also indicate that for approximately 179 seconds the annulus pressure is greater than -0.25 inch WG.

The analysis of the auxiliary building, which is maintained at atmospheric conditions during normal plant operation, indicates that -0.25 inch WG will be attained in 111 seconds after the LOCA. The analysis assumed the building inleakage to be 5000 ft^3/min and a delay of 38 seconds for SGTS startup.

The applicant analysis of the fuel building, which is normally maintained at atmospheric pressure, indicates that the -0.25 inch WG will be attained in 31 seconds. The analysis assumed an inleakage of 5000 ft^3/min and the fuel building charcoal filtration system delay of 18 seconds.

Before plant operation begins and at each refueling outage, the annulus building, the auxiliary building, and the fuel building, will be tested to verify that the inleakage will not exceed the values used in the analyses (i.e., 2000 ft^3/min, 5000 ft^3/min, and 5000 ft^3/min at pressures of -3.0 inches WG, -0.25 inch WG, and -0.25 inch WG, respectively).

Also, the applicant will perform a test before plant operation and at each refueling outage to verify that the SGTS will draw down the annulus building and the auxiliary building to -0.25 inch WG in less than 173 and 81 seconds, respectively, and the fuel building charcoal filtration system will draw down the fuel building in less than 26 seconds.

On the basis of its review of the applicant analyses and the proposed Technical Specifications, the staff concludes that the secondary containment functional design is in compliance with the provision of BTP CSB 6-3 and is therefore, acceptable.

6.2.4 Containment Isolation System

6.2.4.3 Containment Purge System

Drywell Containment Purge Systems

In Section 6.2.4.3 of the SER, the staff required that the applicant commit to the implementation of a nine-point interim program for assessing the need for use of the purge system. This program would be carried out during the first fuel cycle.

In its letters dated November 8, 1984, and January 31, 1985, the applicant provided its response to this nine-point interim program.

The applicant stated that an analysis was performed to establish the number of hours per year that a containment purge system will have to be used to maintain the airborne activity below 25% of the maximum permissible concentration (MPC) specified in 10 CFR 20 during normal operation. The applicant's analysis indicated that 7300 hours per year are required to limit the airborne activity to 23% of the MPC. The applicant did not provide this analysis for staff review. It should be noted, however, that the proposed 7300 hours of usage is 80% of continuous usage or 20 hours per day. This does not represent a serious attempt at limiting use of the purge system. In the absence of a revised estimate by the applicant, the staff has selected a 2000-hour/365-day limit. The staff has discussed this Technical Specification limit with the applicant.

The applicant also indicated that it will implement a data collection program during the first fuel cycle to collect and evaluate the operating experience with the containment purge systems at the River Bend Station. It should be noted that, as part of this effort, the applicant will be required to determine the minimum size purge valve that can be used to reduce the airborne activity in the containment to levels that are consistent with the provisions of 10 CFR 20.

The applicant stated that a containment access management program has been developed to minimize personnel access and residence time in the containment.

With regard to the drywell purge system, the applicant stated that the use of the system will be limited to 90 hours/year (cumulative) in Operating Mode 3 for either drywell pressure control or for reducing drywell activity level. This limit will be 5 hours/year (cumulative) for Operating Modes 1 and 2 for drywell pressure control, as stated in the staff's nine-point program.

As part of the staff's nine-point program for purge system use, the staff stated that whenever the drywell is being vented, the vent should discharge into the containment; moreover, the containment shall not be vented or purged, whenever the drywell is being vented or purged.

The applicant indicated that such a restriction, i.e., requiring a drywell to containment purge, would significantly increase the radioactivity in the containment and would require additional containment purge time to maintain the containment activity level below 25% of MPC.

To avoid the increase in the containment radioactivity level during drywell pressure control operations, the applicant proposed to operate the containment purge system in conjunction with the drywell purge system. To eliminate the staff's concern about the potential for containment bypass during these pressure control operations, the applicant stated that a qualified, dedicated operator will administer the drywell purge system operation to ensure that the drywell vent path bypassing the containment will not be open for more than 2 minutes/venting operation. The plant's operating procedures will direct the dedicated operator to open one division of supply and exhaust drywell isolation valves (e.g., the inboard valves) and, without delay, to open the other division (e.g., the outboard valves) of supply and exhaust drywell isolation valves. Once the second division is indicated as fully open, the dedicated operator will, in less than 2 minutes, begin to close at least one division of the drywell isolation valves.

Since the applicant has not demonstrated the ability of the drywell purge isolation valve to close under the anticipated accident condition in the drywell, these valves will be required to be locked closed during Operating Conditions 1 through 3. Operability of the 36-inch containment purge valves is discussed in Appendix M.

The applicant indicated that it may elect to utilize the hydrogen mixing system for drywell pressure control with no limitations on the total time for venting during the first fuel cycle.

The concern regarding the use of the hydrogen mixing system for drywell pressure control is the potential of it becoming a suppression pool bypass leakage path. The applicant stated that the suppression pool bypass area with the 6-inch hydrogen mixing system inlet valve open is 0.20 ft^2 which is bounded by the allowable bypass leakage. Therefore, the staff finds the applicant's proposal to use the hydrogen mixing system for drywell pressure control to be acceptable. However, since the applicant has not demonstrated that these valves are capable of closing under accident conditions in the drywell, certain restrictions should be applied. In Operating Modes 1 and 2, the total number of hours used should not exceed 5 hours/365 days and in Operating Mode 3 the number of hours should be limited to 90 hours/365 days.

The applicant stated that, except for Items 1(c) and 3 of Branch Technical Position (BTP) CSB 6-4, the River Bend Station's drywell/containment purge system will comply with the requirements set forth in the BTP. With regard to Item 1(c), the staff has determined that the use of the existing system is acceptable until it is determined, based on the nine-point interim program to be implemented during the first fuel cycle, when purging is needed and what line size is needed to accomplish the function.

With regard to Item 3 of BTP CSB 6-4, recirculation of containment atmosphere will be accomplished through the external purge filter for the first fuel cycle and until the staff completes its evaluation of the report to be submitted at the end of the first refueling cycle.

Finally, the applicant has committed not to use two standby gas treatment system (SGTS) trains in the fast purge mode in Operating Modes 1 through 3 and that in those operating modes, only one SGTS may be used with the normal containment purging, provided that both SGTS subsystems are operable. The staff finds the applicant's commitment acceptable.

6.2.5 Combustible Gas Control in Containment

In Section 6.2.5 of the SER, the staff stated that it will perform a confirmatory analysis to determine the acceptability of the hydrogen generation rate calculated by the applicant. On the basis of the results of its calculations, the staff concludes that the applicant's analyses are reasonably conservative and are, therefore, acceptable. On the basis of its review of the combustible gas control system for compliance with all the acceptance criteria of SRP 6.2.5, the staff concludes that the applicant's design includes acceptable systems for monitoring, controlling, and mixing the hydrogen and oxygen that may be generated in the containment following onset of a LOCA. Specifically, the combustible gas control system satisfies the design and performance requirements of 10 CFR 50.44 (except for those portions dealing with postulated degraded core accidents, which is addressed in Item II.B.8, below); the provisions of RG 1.7; and the requirements of GDC 41, 42, and 43. The system is, therefore, acceptable.

NUREG-0660 Items II.B.7 and II.B.8 - Analysis of Hydrogen Control and 8 - Rulemaking Proceedings on Degraded-Core Accidents

As previously reported in the River Bend SER, the staff requested that the applicant propose a program to improve the plant's hydrogen control capability. Specifically, this includes the hydrogen generated from a metal-water reaction involving up to 75% of the active cladding, which is well beyond the amount of hydrogen specified in 10 CFR 50.44(d).

In response to the NRC request, the applicant proposed a hydrogen igniter system for the River Bend Station, similar to that installed in the Grand Gulf Nuclear Station. As reported in the SER, the applicant has indicated that justification of the adequacy of the igniter system will be the generic findings of the Hydrogen Control Owners Group (HCOG), as supplemented by plant-specific design considerations. The NRC published an amendment to the hydrogen rule, 10 CFR 50.44, on January 25, 1985 (50 FR 3498). This amendment, which affects the River Bend Station, became effective on February 25, 1985.

In accordance with the above-cited amendment to 10 CFR 50.44, the staff requires compliance with 10 CFR 50.44(c)(3)(iv)(A) before authorizing operations above 5% of full power. A preliminary analysis of the proposed hydrogen igniter system will be needed which describes the system design and which addresses:

(1) the peak containment pressure resulting from the postulated hydrogen combustion

(2) the peak pressure capability of the containment

(3) the survivability of essential equipment

For this preliminary analysis, the applicant may adopt by reference any prior analyses that may be applicable to the River Bend Station. However, all significant plant-unique features of the River Bend Station will have to be addressed in the applicant's submittal.

Also, consistent with 10 CFR 50.44, as amended, the staff finds that for operations below 5% of full power, the hydrogen igniter system is not needed.

6.2.6 Containment Leakage Testing

6.2.6.3 Type C Test

Penetration Valve Leakage Control System (PVLCS)

In Section 6.2.6.3 of the SER, the staff indicated that the applicant had proposed to air leak test the valves equipped with the PVLCS but exclude the measured leakage from the combined leak rate for the local Type B and C leak rate tests, i.e., 0.6 L_a.

The PVLCS is composed of two independent redundant systems. The elimination of leakage is accomplished by creating a pressure barrier at the closed containment isolation valve by injecting air into the space between the seats of the double-disc gate valves. However, since the system is manually operated and it takes about 30 minutes from the onset of a LOCA before the PVLCS becomes fully

...valves during the initial 30-minute period. ...potential exists for containment effluent to leak through

In FSAR Amendment 19, the applicant indicated that the penetrations served by the PVLCS are required to meet a leakage rate limit specified in Technical Specification 3/4.6.1.2. The applicant further stated that this leakage limit is included in the offsite radiological dose assessment as a separate term.

On the basis of its review of Technical Specification 3/4.6.1, the staff concludes that the applicant's approach in resolving the staff concern regarding leakge from valves equipped with PVLCS is conservative and, therefore, acceptable.

6.3 Emergency Core Cooling System

6.3.3 Performance Evaluation

6.3.3.3 Functional Design

Plant-Specific LOCA Analysis

In its SER (Sections 6.3.3.3 and 15.9.4), the staff reported the results of a lead plant LOCA analysis that was stated by the applicant to be representative of River Bend. The SER also noted that the applicant had committed to supply a plant-specific LOCA analysis for River Bend before fuel loading.

The applicant provided the LOCA analysis specific for River Bend in FSAR Amendment 15 dated November 1984. The plant-specific LOCA analysis included a spectrum of large and small pipe breaks and indicated that the most limiting break is a design-basis break in a recirculation suction pipe. As for the lead plant, an assumed failure of the low-pressure coolant injection (LPCI) diesel generator, coincident with the break, resulted in the worst single failure condition. The plant-specific results demonstrate compliance with the requirements of 10 CFR 50.46 as is shown in Table 6.2 (Revised). From its review, the staff concludes that the plant-specific LOCA analyses for River Bend are acceptable. This issue, Outstanding Issue 8, is closed.

Table 6.2 River Bend LOCA analysis results (revised from SER)

Parameter analyses	Maximum values from break	Allowable
Peak cladding temperature (PCT)	2144°F	2200°F
Maximum cladding oxidation	2.32%	17%
Maximum total hydrogen generation	0.16%	1%

Figure 6.4 (Revised) loss-of-coolant accident chronology (design-basis accident)

7 INSTRUMENTATION AND CONTROLS

7.2 Reactor Protection System

7.2.2 Specific Findings

7.2.2.1 Circuits and Sensors Located in or Routed Through Structures Not Seismically Qualified

Instruments used to monitor turbine control valve (TCV) fast closure, turbine stop valve (TSV) closure, main condenser vacuum, main steamline pressure, and turbine first-stage pressure are located in the turbine building, a structure that is not seismically qualified. These instruments provide inputs to the reactor protection system (RPS), rod control and isolation system (RCIS), containment and reactor vessel isolation control system (CRVICS), and the reactor recirculation system (RRS). The specific instruments, identified in Section 7.2.2.1 of the River Bend SER, are classified as Class 1E, are seismically and environmentally qualified, and are treated as safety related in terms of identification, mounting, and separation.

The staff has reviewed the isolation provided between those portions of instrument channels located in or routed through the turbine building and the downstream safety-related circuits (logic and actuation circuits) to ensure that electrical faults occurring within the non-seismically qualified turbine building will not propagate back to and damage downstream safety-related circuitry. Isolation between faults, which could occur in areas not seismically qualified and the remainder of the protection system is provided in one of two ways. For analog signals, isolation is provided using several stages of relay coil-to-contact isolation between the trip unit outputs and protection system actuation logic. In addition, each cable is run in a separate grounded conduit from the sensor to the protection system cabinets. For digital signals (e.g., limit switch position), isolation is provided using a combination of fuses, circuit breakers, and coil-to-contact isolation. All of the subject instrument channels are designed to "fail safe" (i.e., protective action occurs) on loss of power. In addition, for the TSV and TCV scram signals, diverse (backup) scram signals are provided.

Wiring for all instrument channels is routed in rigid metallic conduit. The wiring and instrument layout in the turbine building is designed to limit the effects of an event to as few channels as possible, so that the ability of the RPS, RCIS, CRVICS, and RCS to perform their safety functions is not degraded. The applicant has stated that an analysis for the effects of a 480-V ac hot short on any RPS channel has been performed and confirms that no safety functions are lost as a result.

On the basis of its review, the staff concludes that sufficient isloation is provided to prevent damage to downstream safety-related circuits from electrical faults occurring in circuits located in areas that are not seismically qualified. This resolves Confirmatory Item 22, as listed in Table 1.4 of the SER and its supplements.

7.2.2.7 Reactor Mode Switch

IE Information Notice 83-42, issued on June 23, 1983, provided information about mode switch malfunctions at several operating reactors. The specific failure mechanism was mode switch contact positioning errors resulting from large design clearances and a tendency for the plastic cam shaft used in the switch to twist (this shaft is actually composed of 22 individual interlocking sections). Subsequently, the General Electric Co. (GE) issued a Field Disposition Instruction (FDI) to the applicant for installation of a new mode switch using a solid metal shaft. However, during functional testing of the upgraded mode switch at Susquehanna Unit 1, problems were encountered regarding proper mode switch operation that resulted in further modifications to the switch. These modifications included cam identification markings, an improved torsion bar/shaft, milled cam surfaces, and external contacts fixed in place with epoxy. Subsequently, the switch was tested successfully, and it was determined that the remodified mode switch would function properly for up to 1000 cycles.

The staff asked the applicant to confirm that the additional mode switch modifications found necessary as a result of functional testing performed on the Susquehanna mode switch have been made to the mode switch at River Bend, and that the new mode switch has been installed and successfully tested. By letter dated February 15, 1985, the applicant stated that a new mode switch has been installed and functionally tested in accordance with the GE FDI. During a telephone conversation on March 20, 1985, the applicant stated that the additional modifications found necessary from testing at Susquehanna, were made to the River Bend mode switch before the switch was shipped to the site. On the basis of this information, the staff considers Confirmatory Item 27, as listed in Table 1.4 of the SER to be resolved. The NRC regional staff will be advised to follow this issue to ensure that the remodified mode switch has been successfully tested before unit startup.

7.3 <u>Engineered Safety Features Systems</u>

7.3.2 Specific Findings

7.3.2.3 ADS Actuation (TMI Action Plan Item II.K.3.18)

The automatic depressurization system (ADS) has been modified in accordance with TMI Action Plan Item II.K.3.18 to automatically initiate in the absence of a high drywell pressure initiation signal. The ADS functions as a backup to the high-pressure core spray (HPCS) system by depressurizing the reactor vessel so that low-pressure systems may inject water for core cooling. In the initial design, each ADS train was actuated upon coincident signals of reactor vessel low water level (two level 1 signals and one level 3 signal are required), high drywell pressure (two signals required), a low-pressure emergency core cooling system (ECCS) pump running (one of two pumps), and a 105-second time delay which allows ADS to be bypassed if the operator believes the actuation signal is erroneous or if vessel water level can be restored. However, for transient and accident events which do not produce high drywell pressure, and are further degraded by a loss of HPCS, manual actuation of the ADS would be required to ensure adequate core cooling.

In order to eliminate the need for manual ADS actuation to ensure adequate core cooling, the applicant has installed bypass timers which will automatically

bypass the drywell high-pressure inputs required for ADS actuation if reactor vessel water level remains below the ADS initiation setpoint (level 1) for a sustained period (approximately 6 minutes). Thus ADS actuation will occur in the absence of a drywell high-pressure signal after the 6-minute delay, and the additional 105-second delay, if a reactor vessel low-water-level condition still exists and a low-pressure ECCS pump is running. Annunciation is provided in the control room when the 105-second timers and the high drywell pressure bypass timers are initiated. Annunciation is also provided when a reactor vessel low-water-level or drywell high-pressure condition is detected.

Four time delays have been added, one for each ADS drywell high-pressure initiation channel. There are two ADS actuation channels (Division 1 and Division 2), either of which can perform the required ADS function. There are two bypass timers associated with each ADS division. The staff will require that the River Bend Technical Specifications contain provisions for periodic surveillance and calibration of the high drywell pressure bypass timers automatically reset when vessel level increases above level 1.

Another modification made to the River Bend ADS consists of the addition of two ADS inhibit switches (one per ADS division) that permit the operator to override the ADS automatic blowdown logic if necessary. These manual inhibit switches prevent automatic ADS actuation, but do not inhibit the safety/relief valve (SRV) pressure-relief function, manual ADS actuation, or individual SRV control. The addition of the ADS manual inhibit switches will simplify the execution of those steps in the Emergency Procedures Guidelines (EPGs) related to mitigation of anticipated transient without scram (ATWS). The inhibit switches are two-position (NORMAL and INHIBIT), maintained-contact, keylock switches. Placing a switch in the INHIBIT position, which defeats the ADS automatic actuation logic for the associated division, causes "ADS OR SRV INOPERATIVE" annunciation in the control room for that division and actuates an "ADS INHIBITED" status light on control room panel 1H13*P601.

The staff concludes that the River Bend ADS design conforms to the requirements of TMI Action Plan Item II.K.3.18 regarding ADS automatic actuation to ensure adequate core cooling, and therefore, is acceptable. This resolves Confirmatory Item 28, as listed in Table 1.4 of the SER and its supplements.

7.4 Systems Required for Safe Shutdown

7.4.2 Specific Findings

7.4.2.3 Standby Liquid Control System

The River Bend standby liquid control system (SLCS) design includes an interlock which prevents the boron storage tank suction valves (C41-F001A&B) from opening in response to a system level manual initiation signal if test tank suction valve C41-F031 is open. The interlock is provided to prevent dilution of the sodium pentaborate solution (from water in the test tank). During its initial review, the staff raised the concern that SLCS inoperable status indication (annunciation) was not provided in the control room when valve C41-F031 is open. Valve position indication lights are provided; however, the staff does not consider valve position status lights to be a positive indication of safety system inoperability.

By letter dated February 5, 1985, the applicant submitted an SLCS design change to provide an additional annunciator point on control room panel 1H13-P601 which indicates "SLCS INOP - F031 NOT FULLY CLOSED." This alarm function will be provided by a Division 2 limit switch mounted at valve C41-F031. The input to the annunciator is routed through an isolator assembly to isolate divisional circuits from the non-safety-related annunciator system.

On the basis of its review, the staff concludes that adequate indication of SLCS inoperability is provided in the control room when test tank suction valve C41-F031 is open. This resolves Confirmatory Item 33, as listed in Table 1.4 of the SER. The staff will verify during the Technical Specification review for River Bend that periodic testing of the interlock function is performed to ensure that the interlock has not failed in a manner that precludes the SLCS function.

7.5 Information Systems Important to Safety

7.5.2 Specific Findings

7.5.2.5 Temperature Effects on Level Measurements

The staff was concerned that high drywell temperatures causing water density changes in reactor vessel water level instrument sensing lines could result in non-conservative false level indications in the control room (i.e., indicated level higher than actual level). Vessel level is determined by measuring the difference in head between a fixed reference column of water (connected to the reactor vessel steam space via a condensing chamber) and a variable column of water which changes with actual level in the vessel (i.e., differential pressure instruments are used). If the change in head due to density changes from drywell heatup for both the reference and variable legs is not equal, a measurement error is introduced. The amount of error is dependent upon the difference in vertical drop between the reference and variable legs inside the drywell.

By letter dated November 21, 1984, the applicant provided information concerning the maximum vessel level indication errors based on the vertical drops of the level sensing lines inside the drywell, the calibration conditions (temperature and pressure) for the level instruments, and a maximum drywell temperature of 340°F. The data provided indicate that with the exception of the fuel zone range instruments, vessel water level indication errors are in the conservative direction (i.e., indicated level is lower than actual level). This included the narrow- and wide-range instruments; the wide-range instruments provide level indication from approximately 2 to 3 inches above the top of the active fuel (TAF) to approximately 50 inches below the centerline of the main steamlines. The maximum error in level indication for the fuel zone range instruments is 11.02 inches in the non-conservative direction. The fuel zone range instruments monitor vessel level from the bottom of the fuel to 50 inches above TAF. There are no protection or control functions performed by the fuel zone range instruments. The applicant has stated that the River Bend Station emergency operating procedures will contain information which allows the operators to determine the maximum water level measurement errors given drywell heatup beyond normal ambient conditions.

On the basis of its review, the staff concludes that the difference in vertical drop between reactor vessel water level instrument sensing lines (reference and

variable legs) inside the drywell will not result in false level indications beyond the capability of the control room operator(s). This resolves Confirmatory Item 35, as listed in Table 1.4 of the SER.

7.6 Interlock Systems Important to Safety

7.6.2 Specific Findings

7.6.2.4 End-of-Cycle Recirculation Pump Trip

Two redundant Class 1E actuation logics [engineered safety features (ESF) Division 1 and ESF Division 2] are provided to initiate an end-of-cycle recirculation pump trip (EOC-RPT) on either TSV closure or TCV fast closure. Either logic division will trip both recirculation pumps. In the original design, each logic was automatically bypassed when the reactor power level decreased below 30% of rated as sensed by a single-turbine first-stage pressure transmitter (C71-N052A and C71-N052B for Divisions 1 and 2, respectively). This raised staff concerns that a transmitter or sensing-line failure could effectively bypass the EOC-RPT function of a given division, and that such a failure might go undetected.

Since the initial review, two additional turbine first-stage pressure transmitters (C71-N052C and C71-N052D) have been provided, and the EOC-RPT automatic bypass logic has been changed to 2-out-of-2 logic for each division. The bypass for a given division is automatically removed when either associated turbine first-stage pressure channel senses that pressure has increased above the setpoint (i.e., pressure has increased above that corresponding to 30% reactor power). Thus, no single failure can cause automatic bypass of the EOC-RPT function for a given division, nor can any single failure prevent the bypass condition from being automatically removed when the conditions that permit the bypass are no longer satisfied. The turbine first-stage pressure instrument channels are powered from the reactor protection system (RPS) buses. Isolation between circuits powered from the RPS and ESF buses is provided using Potter-Brumfield MDR relays. These relays have been found acceptable as isolation devices as discussed in Section 7.2.2.6 of the River Bend SER.

Annuciation is provided on control room panel 1H13*P680 at a single annunciator point, "CONTROL VALVE FAST CLOSURE AND TURBINE STOP VALVE TRIP BYPASS," when any of the four turbine first-stage pressure instrument channels detect pressure less than the bypass setpoint. These same channels are also used to bypass the reactor scram function on TCV and TSV closure when reactor power is less than 30% of rated power. Two 2-position (NORMAL and INOP) maintained contact switches are provided (S9A for Division 1 and S9B for Division 2) which allow the operator(s) to manually bypass the EOC RPT function. Placing either switch in the INOP position will bypass the associated division of EOC RPT logic, and will cause annunciation in the control room indicating the bypass condition, "RECIRC PUMP TRIP SYS A (B) IN MANUAL BYPASS."

Transmitters C71-N052A, B, C, and D provide inputs to trip units C71-N652A, B, C, and D, respectively. These trip units are located at control room cabinets 1H13*P691, 2, 3, and 4 (RPS cabinets). The trip units contain panel meters that display the value of the measured parameter which can be scaled in units of the process variable. The meters are not considered an integral part of the safety system channels, since they are not in series with the transmitter

current loops. The meters monitor the normalized voltage at the output of the input buffer amplifiers (this voltage varies from 1 to 5 V for a corresponding 4- to 20-mA signal from the transmitter). The staff has determined that these meters are adequate for performing instrument channel checks to periodically verify that the output values of all four turbine first-stage pressure channels are within an acceptable band. A deviation of one output value from the remaining three is indicative of a channel malfunction. The staff will verify that the River Bend Technical Specifications contain provisions for channel checks of the turbine first-stage pressure instrument channels.

On the basis of its review, the staff concludes that adequate indication of an EOC-RPT bypass condition is provided in the control room consistent with the requirements of Section 4.13 ("Indication of Bypasses") of IEEE Std. 279-1971, and that sufficient means are provided to assess channel behavior during operation to verify that the turbine first-stage pressure intrument channels are functioning properly. This resolves Confirmatory Item 37, as listed in Table 1.4 of the SER and its supplements.

7.7 Control Systems

7.7.2 Specific Findings

7.7.2.3 Emergency Response and Information System (ERIS)

The ERIS is designed to collect, store, and process plant data from both safety-related and non-safety-related systems, and to provide visual (Cathode-ray tube,CRT) displays of plant status information and printed records of transient events. The ERIS will be used to monitor more than 1400 test points during startup transient testing, as identified by the ERIS input/output signal list for River Bend. More than 1000 of these will remain connected after startup. The staff's preliminary review of the ERIS identified the following areas requiring additional information to complete the review:

- isolation between the non-safety-related ERIS and safety-related input circuits
- failure of the ERIS data acquisition system (DAS) self-test circuits, and the effect on safety-related circuits
- the software development and qualification program applied to the ERIS, and the criteria, controls, quality assurance, and testing procedures applied during software development and production to independently verify that the software design conforms to the functional requirements
- susceptibility of the ERIS to noise/interference and line surges/spikes
- use of the ERIS to perform surveillance required by the plant Technical Specifications

Subsequently, the applicant provided additional information concerning these items and the ERIS design was reviewed during meetings held between the staff and the vendor (GE).

The staff reviewed ERIS drawings and identified the safety-related and non-safety-related portions of the system. The isolation provided between safety-related and non-safety-related circuits was reviewed and found to conform with the guidelines of NUREG-0737, Supplement 1 ("Clarification of TMI Action Plan Requirements: Requirements for Emergency Response Capability"), issued by Generic Letter 82-33. Isolation is accomplished using fiber optic cable which varies in length from 2 feet to 5000 feet. Characteristics of fiber optic cable include nonsusceptibility to the coupling of crosstalk and electromagnetic interference (EMI). Because optical fibers are totally dielectric, the electrical energy resulting from a fault at the output/non-Class 1E end of the cable will not propagate through the cable, and thus, will not degrade circuits at the input/Class 1E end. power generation control complex

All inputs to the ERIS enter through remote input modules (RIMs). Two types of RIMs are used: GEDAC-4800 and GEDAC-5500. GEDAC-4800 modules are qualified as Class 1E devices to IEEE Stds. 323-1974 and 344-1975. The GEDAC-5500 modules are used in applications that are not Class 1E. The remainder of the ERIS (downstream of the RIMs) is not Class 1E. Inputs to the ERIS from a given division are routed to a cabinet (which houses the RIMs) located above the divisionally associated (PGCC) termination cabinet in the control room. Some RIMs are mounted locally. In these cases, the signals are transmitted to the control room via fiber optic cable. The RIMs, multiplexers (MUX), and data formatter module (DFM) are combined to form the DAS portion of the ERIS. Each DAS component executes a self-test routine which checks for valid hardware and software within the module as well as for valid external connections where possible. The applicant has stated that failure of the DAS self-test circuitry has been analyzed and demonstrated not to impair safety-related signals. Alarms are provided in the ERIS/DRMS (digital radiation monitoring system) computer room upon DAS self-test detected failures. The applicant has indicated that this room is continuously manned during normal operation.

The staff is currently reviewing the software methodology used and implementation of the methodology in the final ERIS design (i.e., verification and validation, V&V) as part of the evaluation of the generic safety parameter display system (SPDS) proposed for GESSAR II. GE has stated that the basis for the V&V program used in the design of the ERIS was NSAC-39 (Verification and Validation for Safety Parameter Display Systems). The staff has reviewed this program and found it to be in conformance with the guidelines of NUREG-0737, Supplement 1, and therefore acceptable. A draft evaluation of the GESSAR II SPDS is provided as the enclosure to a letter dated December 18, 1984 from C. Thomas, NRC, to G. Sherwood, GE. Those aspects of the V&V program for the GESSAR SPDS which are still under review will be addressed in the staff's final evaluation, scheduled to be completed by May 1985.

The Class 1E portions of the ERIS are designed in accordance with IEEE Std. 472-1974 ("Guide for Surge Withstand Capability"). In addition, the ERIS Class 1E components were tested for susceptibility to electromagnetic interference (EMI), including radiofrequency interference (RFI) (e.g., walkie-talkies), in accordance with GE qualification program standard procedures.

FSAR Section 7.7.1.7.2 indicates that the ERIS will be used to aid plant personnel in performing routine surveillance tests during commercial operation. This raised staff concerns regarding the use of the ERIS for testing safety-related instrumentation. However, the applicant has stated that the ERIS will

not be used to satisfy any Technical Specification surveillance requirements for protection system instrument or logic channels. The ERIS will be used for scram time testing and integrated leak rate testing.

On the basis of its review, the staff concludes that the ERIS satisfies the applicable criteria identified in Section 7.7 of the Standard Review Plan (NUREG-0800), and therefore, is acceptable. This resolves Confirmatory Item 43, as listed in Table 1.4 of the SER.

8 ELECTRIC POWER SYSTEMS

8.3 Onsite Emergency Power Systems

8.3.1 AC Power Systems

In Section 8.3.1 of the River Bend SER, the staff stated that it wished to review a revised figure of the electrical protection assembly (EPA) reactor protection system (RPS) motor generator set interconnections in order to confirm the adequacy of the installation of the EPAs and interconnections between the non-Class 1E RPS motor generator sets and Class 1E alternate power supplies.

During its February 27-28, 1985, site visit, the staff viewed the installation of the EPAs between the RPS motor generator (MG) sets and the RPS buses, and between the RPS alternate power supplies and the RPS buses. From this and its previous review, the staff concludes that the Class 1E EPAs are electrically and physically redundant and independent and are, therefore, acceptable. The isolation provided between the non-Class 1E RPS buses and the Class 1E alternate power supplies is discussed in Section 8.4.6 of this supplement.

8.3.2 DC Power Systems

In SER Section 8.3.2, it was stated that a backup battery charger had the capability of being connected to any of three safety or three non-safety dc buses by way of a separate 125-V dc switchgear that has connections to each bus. In FSAR Amendment 19 the applicant has subsequently deleted the connection of the Division III (HPCS) safety bus to the backup battery charger 125-V dc switchgear. This change does not impact the staff's previous evaluation because the staff had originally given no credit for the backup charger as a replacement for the normal safety battery chargers, because the backup charger is supplied from a non-safety ac bus.

8.4 Other Electrical Features and Requirements for Safety

8.4.5 Physical Identification and Independence of Redundant Safety-Related Electrical Systems

The staff indicated in its May 1984 evaluation (River Bend SER, NUREG-0989) that Class 1E cables installed in cable trays dedicated to 4160-V or large 480-V power circuits, where spacing is maintained between cables installed in a single layer, are not color coded at 5-foot intervals. The staff stated it would confirm the adequacy of this in a supplement to the SER.

Subsequently, in FSAR Amendment 16, the applicant stated that all cables except for the cables run entirely in conduit would be color coded by painting the cable jacket at intervals not exceeding 5 feet or by the use of cables with color-coded jackets. This is in conformance with Position C.10 of Regulatory Guide (RG) 1.75 and is, therefore, acceptable.

FSAR Amendment 16 also stated that cables with red- or blue-colored jackets may be used on unscheduled non-Class 1E circuits that run exclusively in conduit, only when the following mandatory conditions have been implemented:

(1) Neutral tags indicating non-Class 1E circuits are permanently attached at each end of the cable run and wherever the cable is exposed, and field quality control has verified 100% that this condition has been met.

(2) No color-jacketed cable used for unscheduled non-Class 1E application is allowed to be terminated in or pass through an enclosure (pull box, junction box, cabinet) containing divisional Class 1E circuits.

The staff finds that these exceptions to cable color coding, with the above-stated restrictions, will not decrease the effectiveness of the color coding system used at River Bend and are, therefore, acceptable.

In FSAR Amendment 16 and by letter dated January 28, 1985, the applicant stated its intent to justify the use of lesser cable separation at River Bend by performing tests using the reduced separation distances. The reduced separation distances are limited to circuits rated less than 4160 V. The original cable separation distances committed to by the applicant were the standard separation distances outlined in IEEE Std. 384-1974. In lieu of using the standard separation distances outlined in IEEE Std. 384-1974, the IEEE standard allows the separation distances to be established by analysis based upon tests of the proposed cable installations.

The applicant's tests, as outlined in Wyle Test Report No. 47618-02 dated April 12, 1985, consisted of screening tests and configuration tests. The screening tests consisted of overcurrent tests on different size cables used at River Bend to determine which cable size, if subjected to a worst-case electrical fault, would have the most impact on adjacent cables. The worst-case electrical fault on a cable was taken to be the lesser of the locked rotor current (6 times full load amperes) or the fault current level just below the longtime trip of the upstream protective device plus 10%. If the insulation should burn off the conductors during these tests, the bare conductors would be exposed and the temperatures would decrease. Under real circumstances the bare conductors would short circuit and the fault current level would increase. The test currents were, therefore, increased to simulate the short circuit in this eventuality. Before energizing the cable with the worst-case electrical fault, warmup current was applied to the cable until the conductor temperature reached 90°C, which is the maximum normal operating temperature. Fault currents were applied to the cables until they open-circuited. The worst-case cable as established by the screening tests was a Triplex 2 AWG copper cable. This size cable was used as the faulted cable in each of the configuration tests.

The configuration tests were run to demonstrate the acceptability of various cable separation configurations simulating those used at River Bend. The tests consisted of injecting a Triplex 2 AWG copper cable with a worst-case fault current as was done during the screening test and measuring temperatures and observing the effects on various target cables in the vicinity of the fault cable. The target cables were energized and carrying rated current which was monitored during the course of the test. Following completion of each configuration test, an insulation resistance test and a high potential test were performed on the target cables to determine the adequacy of their insulation. In

all cases the target cables successfully passed the insulation resistance and high potential tests.

The staff, however, was concerned that the temperatures recorded on the target cables during two of the configuration tests were extremely high. These were configuration 2, test 2 (688.9°F), and configuration 4, test 2 (786.6°F). The configuration 2 test was conducted to demonstrate the adequacy of Siltemp 188 CH wrap as a barrier between two cables in free air with zero separation. Although the target cables in this test passed the insulation and high potential tests, the maximum temperature of 688.9°F recorded on the target cable was much greater than temperatures recorded during the other configuration tests with the one exception noted above. The subject test, however, was performed with three layers of the protective wrap while the applicant's updated separation criterion (Drawing 12210-EE-34ZE) calls for four layers of the protective wrap. An additional test (configuration 2, test 1A) conducted with four layers of the protective wrap resulted in a target cable temperature of 379.4°F, confirming the adequacy of four layers of the protective wrap.

The configuration 4, test 2, in which a high temperature of 786.6°F was recorded, was conducted to demonstrate the adequacy of a configuration in which a horizontal aluminum conduit runs perpendicular to and in contact with a fault cable in a vertical tray. As above, the staff was concerned that the temperature (786.6°F) was well in excess of temperatures recorded during the other configuration tests. The high temperature, however, only existed briefly. Following ignition of the fault cable, the temperature on the target cable rose rapidly from 150°F to the peak of 786.6°F in 4 minutes, then immediately began falling to 370°F in the next 4 minutes. The ignition of the fault cable which started the dramatic rise in target cable temperature also did not occur until 17.3 minutes after fault current was applied to it. High impedance faults of the magnitude applied to the fault cable will not normally exist for that length of time. They generally degrade into low impedance faults which then quickly trip circuit breakers or burn clear. Regardless of the likelihood of the tested fault conditions, however, the test report states that following this test there was no visual evidence of damage to any target cable; and the target cable from the conduit which saw the high temperature was in good shape after exposure to flames all around the conduit. The target cable also easily passed the high potential and insulation resistance tests, and the applicant has taken additional measures to ensure that in actual application the horizontal conduit will be separated a minimum of 1 inch from the vertical tray. The staff, therefore, finds this configuration acceptable.

On the basis of the tests conducted, the staff finds the proposed electrical separation at River Bend to be acceptable. The applicable separation distances are provided in the applicant's letter dated May 9, 1985. The applicant committed to provide this information in a future FSAR amendment. The reduced separation applies only to circuits less than 4160 V.

8.4.6 Non-Safety Loads on Emergency Sources

In FSAR Amendment 16, the applicant identified (in Table 8.3-7) additional non-Class 1E equipment supplied from Class 1E buses. These loads are unqualified heaters furnished with Class 1E motor-operated valves (MOVs), the RPS buses, and the main control room lighting system transformers. Each of these is discussed below.

In Section 8.4.6 of the SER, the staff identified the main control room lighting as a non-Class 1E load on a Class 1E power source. FSAR Amendment 16 to Table 8.3-7 clarifies that the lighting transformer is not procured Class 1E although it is identical in design and construction to RBS Class 1E small dry-type transformers. The lighting transformer is connected to either of its alternate Class 1E sources of power via a series-connected circuit breaker and fuse located in the Class 1E motor control centers. During its site visit, the staff reviewed coordination curves which confirmed that the circuit breakers and fuses to the lighting transformer had adequate coordination with the upstream feeded breakers which feed the Class 1E motor control centers. The staff finds these provisions acceptable and will ensure that the River Bend Technical Specifications contain a requirement for periodic testing of these overcurrent devices.

Also during its site visit, the staff discussed with the applicant the isolation provided between the Class 1E RPS alternate power supplies and the non-Class 1E RPS buses. The alternate supply is taken from a regulating transformer which is powered from a Class 1E motor control center (MCC). Between the transformer and the RPS bus are connected two in-series, redundant and independent EPAs. The applicant provided a short-circuit analysis which indicated that the available fault current to the RPS bus is insufficient to cause degradation or tripping of the Class 1E MCC. There are also two circuit breakers in series, one at the MCC and one integral with the regulating transformer assembly, which are coordinated with the MCC feeder breaker at the load center to preclude tripping of the MCC for faults on the RPS. In addition, the EPAs would likely trip on low voltage for any fault large enough to degrade the Class 1E MCC if a fault of that magnitude could exist. The staff considers these provisions sufficient to prevent a fault on the non-Class 1E portions of the RPS from degrading the Class 1E MCC.

FSAR Amendment 16 states that non-Class 1E heaters mounted in Class 1E motor-operated valves and temporarily connected to Class 1E panelboards during the construction phase are de-terminated at the panelboards after equipment release and before exceeding 5% power. Because the unqualified heaters will have no connection to the Class 1E system during or following 5% power operation, the staff finds this acceptable.

FSAR Amendment 19 has identified further additional non-Class 1E equipment connected to Class 1E power supplies. These are the polar crane in the reactor building, the monorails in the standby cooling towers, unqualified slide wire transducers used for valve position indication on selected residual heat removal (RHR) valves, and unqualified limit switches used for check valve position indication. The monorail circuits are tripped on a LOCA signal. This is in accordance with RG 1.75 and is, therefore, acceptable. The circuit breaker for the polar crane is locked in the open position during plant operation and is closed and energized only during periods of reactor maintenance. This is an acceptable variation of the RG 1.75 requirements. For the slide wire transducers and limit switches, the FSAR states that evaluation has demonstrated that open, short, or ground circuits in these components will have no adverse effects on the Class 1E portion of the circuit. The applicant should provide this evaluation to the staff so that it can make an independent confirmation of this statement. The staff will report on this issue in a future supplement to the SER.

8.4.7 Flooding of Electrical Equipment

The staff indicated in its initial report that it would evaluate the applicant's analysis and proposed fixes relating to the flooding of electrical equipment as the result of a loss-of-coolant accident (LOCA) and report the results in a supplement to the SER.

In a letter dated February 15, 1985, the applicant provided a revision to Section 2.4 of the River Bend Equipment Qualification Document (EQD) which addressed the subject of submergence. It states that equipment located inside the containment is designed and qualified to perform its intended function while submerged. Equipment located inside the drywell that is subjected to submergence is not required to perform an active safety function, and the applicant's evaluation has demonstrated that subsequent failure of this equipment is without significant consequences.

The staff was concerned that unqualified motor-operated valve control circuits located inside the drywell might cause spurious operation of the valve when subjected to submergence. During its site visit, the staff reviewed drawings provided by the applicant which indicate that control circuit contacts in the motor control centers isolate the contactor coil of the valve motors from their control circuits in the drywell so that no failure of the circuits in the drywell can cause spurious operation of the valve. For failures that would short these circuits, redundant overcurrent protection is provided as described in Section 8.4.2 of the River Bend SER. The staff finds these provisions acceptable.

8.4.9 Cable Derating for Spacing in Accordance With IPCEA Recommendations

The applicant states in the FSAR that the normal current loading of all insulated conductors is limited to that continuous heating value which does not cause insulation deterioration from heating. The selection of conductor sizes is based on the Insulated Power Cables Engineers Association (IPCEA) publication P-46-426. The applicant further states that cables are derated for grouping and spacing in accordance with IPCEA recommendations.

The staff~~'s Construction Appraisal Team (CAT)~~ raised a concern during its inspection that the spacing between power conductors in trays was maintained at one-fourth of a cable diameter only at the tie points and not necessarily between them, whereas the IPCEA derating factors used at River Bend are based on cables with maintained spacing of between one-fourth to one cable diameter.

Subsequently, in a letter dated December 5, 1984, the applicant referenced testing that was conducted which demonstrated that the temperature of the energized cable will not exceed the design rating of the cable with only intermittent touching. The staff has reviewed the results of this test and agrees, on the basis of these results, that the derating factors used at River Bend, which were IPCEA recommendations, are conservative. Furthermore, the design temperature of the cable is not exceeded by allowing adjacent cables to occasionally touch or be separated from each other by less than one-fourth of a cable diameter between tie points. In a December 5, 1984, letter, the applicant emphasized that the one-fourth of a cable diameter spacing is still an intended goal at the time of installation, as it must be maintained at tie points both during and after installation. This issue (Confirmatory ~~Issue~~ Item 79) is, therefore, resolved.

9 AUXILIARY SYSTEMS

9.1 Fuel Storage and Handling

9.1.5 Overhead Heavy Load Handling System

As a result of Generic Task A-36, "Control of Heavy Loads Near Spent Fuel," NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," was developed. Following the issuance of NUREG-0612, a generic letter dated December 22, 1980, was sent to all operating plants, applicants for operating licenses, and holders of construction permits requesting that responses be prepared to indicate the degree of compliance with the guidelines of NUREG-0612. As indicated above, in accordance with the generic letter of December 22, 1980, the applicant was asked to review the provisions for the handling and control of heavy loads at the River Bend facility to determine the extent to which the guidelines of NUREG-0612 are satisfied and to commit to mutually agreeable changes and modifications that would be required in order to fully satisfy these guidelines. By submittals dated June 24, 1981; March 1, 1984; November 5, 1984; and January 8, 1985, the applicant provided the responses to this request.

The staff and its consultant, EG&G, of the Idaho National Engineering Laboratory (INEL), have reviewed the applicant's submittals for the River Bend Station. As a result of its review, EG&G has issued a technical evaluation report (TER). The staff has reviewed the TER and concurs with its findings that the guidelines in NUREG-0612, Section 5.1.1 have been satisfied. This TER is a part of this SER (Appendix I). The staff concludes that Phase I of NUREG-0612 for the River Bend Station is acceptable. The staff further concludes that with the completion of Phase I and based on the above response and Phase II review to date, no further action is required concerning Phase II of NUREG-0612. Therefore, the staff concludes that the requirements of GDC 4 and 61 and the guidelines of Regulatory Guide 1.13, Positions C.3 and C.5, have been satisfied for the overhead heavy load handling systems at River Bend Station, Unit I.

9.2 Water Systems

9.2.2 Reactor Plant Component Cooling Water System (Reactor Auxiliary Cooling Water System)

In the SER, the staff stated that the safety-related portion of the reactor plant component cooling water (RPCCW) system is automatically isolated from the nonessential portion of the RPCCW in the event of an accident, such as a LOCA. In FSAR Amendment 15, the applicant deleted the reference to isolation during an accident. The automatic isolation is initiated by a low water pressure signal. An accident may result in a low water pressure in the RPCCW system and thereby result in isolation of the nonessential portion, but an accident, such as a loss of offsite power, will not directly result in isolation. This change does not affect the staff's conclusions as discussed in the SER.

9.3 Process Auxiliaries

9.3.2 Process Sampling System

Item II.B.3 - Post-Accident Sampling System

This subject is discussed in Section 10.4.6 of this River Bend supplement.

9.4 Air Conditioning, Heating, Cooling, and Ventilation Systems

9.4.5 Engineered Safety Feature Ventilation Systems

9.4.5.1 Diesel Generator Building Ventilation System

In the SER, the staff stated that each of the three diesel generators is serviced by two redundant exhaust fans. In FSAR Amendment 15, the applicant has eliminated one of the 100% exhaust fans in each diesel generator compartment. The failure of the single exhaust fan could result in the failure of the associated diesel generator. The failure of a diesel generator has previously been considered; therefore the failure of a diesel generator owing to the failure of the exhaust fan does not represent any new accident scenario. Therefore the

elimination of one 100% capacity exhaust fan per diesel generator is acceptable. This does not affect the staff's conclusions as discussed in the SER.

9.5 Other Auxiliary Systems

9.5.2 Communication Systems

9.5.2.1 Intraplant Systems

In the SER, the staff noted that the intraplant communications were powered from non-Class 1E power sources and could not be connected to an onsite power source following a loss of offsite power (LOOP). The staff requested that the applicant describe how it would maintain adequate communications between the control room and safety-related areas throughout the plant, assuming a design-basis seismic event and/or a LOOP in excess of 4 hours (intraplant communications have a 4-hour-rated, non-Class 1E battery backup). The applicant, in an FSAR amendment, stated that the plant design and accident analysis was such that the plant could be brought to safe cold shutdown from the control room, considering any design-basis event, without the need to leave the control room or communicate with any location outside the control room. On this basis, the applicant concluded that Class 1E communications and power supplies were not necessary. The staff has reviewed the applicant's response and the River Bend accident analysis. On the basis of its review, the staff concurs with the applicant's assessment of shutdown capability from the control room.

The staff concludes that the intraplant communications at River Bend conform to the standards, criteria, and design bases and can perform their design functions, and is, therefore, acceptable. This finding is subject to confirmation that appropriate procedures covering shutdown from the control room only have been developed and implemented, and that operating personnel have been trained in the use of these procedures. These procedures shall be in place before exceeding 5% power.

9.5.3 Lighting Systems

In the SER, the staff identified features of the control room emergency lighting system which were not acceptable. These included a design which would require an operator to restore emergency lighting during a design-basis event and/or LOOP by manually disconnecting a plug from a non-Class 1E receptacle and reconnecting it to a Class 1E receptacle, all within a short time from the event initiation. Another system feature was that a significant portion of the emergency lighting was powered from a non-Class 1E power source. In addition to control room emergency lighting, the applicant had not provided information regarding adequate lighting in safety-related areas outside the control room during and after a design-basis event and/or LOOP.

By FSAR Amendment 15 and by letter dated August 21, 1984, the applicant provided additional information on the design of the control room emergency lighting system. The system was redesigned so that the emergency lighting would always be connected to a Class 1E source, usually Division I, and that manual reconnection for another Class 1E source would only be necessary in the event of failure of the original Class 1E source (i.e., reconnect to Division II in the event Division I fails). Since there will be adequate lighting from seismically mounted battery packs to perform this operation, and the potential of having to make a reconnection is low, the staff finds this acceptable. The applicant also provided additional information on the design, qualification, and installation of transformers, distribution panels, cables, conduits, raceways, and system isolation devices associated with the control room emergency lighting system which demonstrates that these items are Class 1E or equivalent. On this basis, the applicant concludes that emergency lighting for the control room would be available during and/or after any design-basis event, including a seismic event. The staff concurs with the applicant's conclusions. The applicant also provided information which showed that the emergency lighting system would maintain illumination levels of 25 foot-candles in the control room. This also is acceptable.

The applicant responded to the staff's concerns regarding emergency lighting in safety-related areas outside the control room. The applicant stated that the plant design and accident analysis was such that the plant could be brought to

a safe cold shutdown from the control room, considering any design-basis event, without the need to leave the control room or occupy any safety-related areas. On this basis, the applicant concluded that lighting in safety-related areas that would be available following any design-basis event, including seismic, was not required. The staff has reviewed the applicant's response and the River Bend accident analysis and concurs with the applicant's assessment of shutdown capability from the control room.

The staff concludes that the lighting systems at River Bend conform to the standards, criteria, and design bases can perform their design functions, and is therefore acceptable. This finding is subject to confirmation that appropriate procedures covering shutdown from the control room only have been developed and implemented, and that operating personnel have been trained in the use of these procedures. These procedures shall be in place before exceeding 5% power.

9.5.4 Emergency Diesel Engine Fuel Oil Storage and Transfer System

9.5.4.1 Emergency Diesel Engine Auxiliary Support Systems

In the SER, the staff concluded that the applicant had not provided sufficient information to demonstrate that the training for operations, maintenance, and supervisory personnel on emergency diesel generators would be equivalent to vendor training. By letter dated August 21, 1984, the applicant stated that "River Bend Station has implemented the staff's recommendation of providing vendor training, or that equivalent to vendor training, for the operations and maintenance department personnel (including supervisors)." On the basis of the applicant's response, the staff concludes that the applicant's initial training program is acceptable since it utilizes vendor training. The applicant also stated that there would be a program for retraining, but did not specify if it would be vendor training or in-house training. By letter dated June 5, 1985, the applicant provided additional information on the retraining program to be implemented at River Bend. Site-specific training manuals for both types of diesel generators have been developed based on vendor materials and with assistance from vendor consultants. Retraining will be at intervals not exceeding

2 years. Therefore, the staff concludes that diesel generator training at River Bend is acceptable.

By letter dated March 5, 1984, the applicant provided a discussion of high-pressure core spray (HPCS) diesel generator testing. The applicant stated that no-load or light-load operation will be minimized and that the engine will be cleared in accordance with manufacturer's recommendations following extended periods of no-load operation. The preventive maintenance program for the HPCS diesel generator will go beyond normal routine adjustments, servicing, and repair of components. The program will encompass investigative testing of components that have a history of repeated malfunction and that have required constant attention and repair and have utilized industry operating experience to identify components that affect diesel generator reliability. Following maintenance or extended outage of the diesel generator, a complete system lineup will be conducted to ensure that all electrical and mechanical systems are functional prior to a start attempt. Upon completion of the lineup, the diesel will be started and load tested before being returned to automatic standby service. The staff finds the applicant's discussion of HPCS diesel generator testing and maintenance acceptable.

The applicant was asked to provide diesel generator design data which showed the diesel engines were capable of developing full-rated power under the most extreme conditions of temperature, humidity, and barometric pressure anticipated for the River Bend site. The staff stated that the design of the River Bend diesel generators, with regard to ambient conditions, would be acceptable on confirmation that the requested data had been provided. The applicant provided the information in FSAR amendments, and the staff finds this acceptable.

By FSAR amendment, the applicant provided information regarding the mounting of instrumentation and controls for the standby diesel generators. The applicant stated that, except for sensors and other equipment which must be mounted directly on the engine, the standby diesel generator controls and instrumentation are installed in freestanding, floor-mounted panels located in a vibration-free floor area. The staff finds this acceptable.

In the SER, the staff concluded that there was not sufficient assurance of long-term diesel generator reliability. The staff described specific design changes, procedural modifications, and issues which required implementation and/or resolution in order to ensure long-term diesel generator reliability. The applicant's response to these staff concerns is described below.

(1) Dust and Dirt in the Diesel Generator Room

The applicant provided a discussion of the dust protection for the diesel generator control panels, and of the ventilation system for the diesel generator control rooms. This subject is addressed in Section 9.5.8 of this supplement.

(2) Personnel Training

The applicant provided additional information regarding initial and follow-up diesel generator training. This subject is addressed above in this section of the supplement.

(3) Automatic Prelubucation

The applicant provided additional information regarding the design and operation of lubrication oil system modifications on the HPCS diesel generator. This subject is addressed in Section 9.5.7 of this supplement.

(4) Diesel Generator Room Ventilation System Air Filtration

The design of the diesel generator control panels and diesel generator control room ventilation systems provides adequate dust protection for the diesel generator control systems. This subject is addressed in Section 9.5.8 of this supplement.

(5) Concrete Dust Control

The applicant has committed to comply with the recommendations of NUREG/CR-0660. This subject is discussed in Section 9.5.8 of this supplement.

(6) Vibration of Instruments

The applicant provided data on the mounting of controls for the standby diesel generators. This subject is addressed above in this section of this supplement.

On the basis of information provided by the applicant, the staff concludes that the diesel generators and their auxiliary systems are in conformance with the recommendations of NUREG/CR-0660 for enhancement of diesel generator reliability, and the related NRC guidelines and criteria. The revised Table 9.1 reflects this conformance.

9.5.4.2 Emergency Diesel Engine Fuel Oil Storage and Transfer System

In the SER, the staff identified the concern that the fuel oil storage tanks were not protected from internal corrosion. This lack of protection could result in the formation of corrosion products which could affect diesel generator availability. By FSAR amendment and letter dated August 21, 1984, the applicant addressed the staff's concerns as follows: (1) a fuel stabilizer, such as Apollo Chemical Corp. SDI-35 which inhibits oxidation of fuel oil and the formation of corrosive byproducts, will be added to stored and new fuel as recommended by the manufacturer, (2) the storage tanks will be checked for water and accumulated water removed on a 31-day basis, and (3) the stored fuel will be tested for the presence of particulate matter on a 31-day basis. The staff has reviewed the applicant's program and concludes that the potential for creating corrosion products is greatly reduced, the amount of corrosion products produced would be small in any case, and the presence of potentially harmful particulate would be discovered at an early stage. Therefore, the staff concludes that the absence of internal corrosion protection for the fuel oil storage tank is acceptable.

In the River Bend SER, the staff assumed an event which requires refilling the fuel oil storage tanks during diesel generator operation. The applicant was asked to discuss how it would prevent stirring of sediment in the tanks as a consequence of the refilling operation. This sediment could foul diesel generator fuel system components and cause potential loss of the diesel generator(s).

In FSAR amendments and by letter dated August 21, 1984, the applicant stated that refilling of the storage tanks would be staggered by 24 hours so that only one tank at a time would be affected. In addition, procedures will be implemented to ensure that the day tank (for the associated diesel generator) is full before a storage tank is refilled. This will allow the diesel generator to operate for the longest period of time possible without requiring a transfer of fuel from the storage tank, thereby allowing time for sediment to settle. Finally, the minimum amount of fuel oil in the day tank is adequate to support continued diesel generator operation while fuel oil filters and/or strainers, which may have become clogged by sediment, are cleaned. The strainers have high differential pressure alarms. Therefore, the staff concludes that the applicant's method for controlling sediment in the fuel oil storage tanks is acceptable.

The staff further concludes that the emergency diesel engine fuel oil storage and transfer system is acceptable.

9.5.5 Emergency Diesel Engine Cooling Water System

In the SER, the staff requested that the applicant provide information on the heat removal capability of the standby diesel generator cooling water system. By FSAR amendment, the applicant provided information which demonstrates that the cooling water system has adequate heat rejection capability for the maximum diesel generator load plus a margin to allow for system fouling. The staff finds the applicant's response acceptable.

The River Bend FSAR did not contain sufficient information regarding the capability of the standby diesel generators to operate at no-load, light load conditions for an extended period of time. The applicant, by letters dated March 5, 1984, and July 24, 1985, provided additional information. The staff has reviewed the applicants submittal and finds it acceptable.

The design of the Division III (HPCS) diesel generator cooling water system is such that air is trapped at the high point of the closed-loop system when the diesel generator is in the standby mode. The staff asked the applicant to

demonstrate that this air would not be detrimental to the operational reliability of the diesel generator cooling water system. In FSAR amendments, the applicant provided information that demonstrated compliance with the manufacturer's recommendation for corrosion inhibitors in the cooling water system. The applicant also provided a copy of a letter from the manufacturer which stated that coating the exposed portions of the system with coolant/inhibitor on a monthly basis (by operating the diesel generator) is adequate to prevent corrosion of the exposed surfaces when the diesel generator is in standby. The staff finds this acceptable.

The FSAR did not contain sufficient information regarding diesel generator cooling water system instrumentation and controls for the staff to evaluate their adequacy. In addition, the applicant did not address test and calibration of these controls. By FSAR amendment and letter dated August 21, 1984, the applicant provided this information. The staff has reviewed the additional data and concludes that the design of the diesel generator cooling water system instrumentation and controls, including test and calibration on an 18-month basis, is acceptable.

The applicant was asked to demonstrate that the cooling water systems for both the standby and HPCS diesel generators contained sufficient inventory to support 7 days of continuous diesel generator operation without a requirement to add coolant, assuming normal coolant leakage during operation. The applicant responded to the staff's concern by stating that no makeup water needs were anticipated for 7 days of operation. However, the cooling water system coolant level can be monitored during operation, and if necessary, provisions have been made for adding water to the standby and HPCS diesel generator cooling water systems during operation. The staff finds this acceptable.

In the SER the staff asked the applicant to verify that the HPCS keep-warn system will maintain the cooling water system temperature at a high enough point to enhance diesel engine starting reliability. The applicant, by letter dated July 24, 1985, provided additional information. The applicant stated that the keep-warm system is provided with an electric heater designed to maintain normal engine faiure water and lubrication oil temperatures in a room temperature environment down to 40°F and lower, and that room temperature will be maintained

above 40°F, and it would be alarmed and displayed in the control room. Also a diesel generator trouble alarm is provided in the control room, with local alarm status to warn the operators of inproper operation of several diesel engine functions, including a low engine lubrication ac/temperature condition and a keep-warm system power failure In addition, plant operating procedures will be provided to instruct operators to take immediate and appropriate actions upon actuation of any alarm condition. The applicant stated that the above facts provide adequate assurance that the HPCS diesel generator will reliably start and operate under all anticipated conditions. The staff concurs with the applicant and finds the design of the keep-warm system for the PHCS diesel generator acceptable.

The staff concludes that the standby and HPCS diesel generator cooling water systems will be acceptable subject to confirmation that the applicant has identified the diesel engine interfaces.

9.5.6 Emergency Diesel Engine Starting System

The FSAR had insufficient information on the design and operation of the diesel generator air start systems instrumentation and controls including frequency of test and calibration thereby precluding a complete system evaluation. By FSAR amendments and letter dated August 21, 1984, the applicant provided this information, and stated that test and calibration of the instrumentation and controls would be conducted on an 18-month basis. The staff finds this acceptable.

For the standby diesel generator air start system, there is an unloader line between the air receiver and the system air compressor which is not identified as Safety Class III. The staff's concern was that failure of this non-safety line would cause blowdown of the air receiver with attendant failure of the diesel generator to start on demand. By letter dated June 5, 1985, the applicant stated that the unloader line is seismic Category I, Safety Class III. This resolves the staff concern.

The applicant, by letter dated June 27, 1985, provided additional information relative to the engine-mounted piping on the standby diesel generators. The auxiliary systems for the standby diesel generators are designed, engineered,

manufactured, installed, and tested in accordance with ASME Code Section III, Class 3, requirements up to the connection point on the engine. The engine-mounted piping and components have been designed and installed in accordance with the standards of the Diesel Engine Manufacturers Association (DEMA). In addition, design reviews and quality revalidation inspections were performed on these engine mounted systems in conjunction with the Transamerica DeLaval Inc. (TDI) Diesel Generator Owners Group. The results are documented by the Owners Group in the Phase II Design Review and Quality Revalidation reports submitted December 24, 1984, and March 7, 1985. The acceptability of the standby diesel generator engine-mounted piping and components will be evaluated by the NRC TDI Project Group and will be reported in a future SER supplement.

The air dryers for the HPCS diesel generator air start systems are of the refrigerant type and are designed to deliver dry air at a dewpoint of 35°F with a room ambient temperature of 40°F. Normally the room ambient temperature will be maintained at substantially higher levels than 40°F. The applicant has established a minimum diesel generator room temperature of 40°F to ensure satisfactory dryer operation and satisfactory operation of all other equipment in the diesel generator room which is subject to the same temperature environment limitation.

By letters dated August 21, 1984, and June 26, 1985, the applicant provided the basis for establishing the HPCS diesel generator room temperature at 40°F. As further assurance, the applicant has committed to include in the plant Technical Specifications surveillance of the HPCS diesel generator room temperature on a 24-hour cycle when the room temperature is 50°F or higher and on a 12-hour cycle when the room temperature is less than 50°F. The applicant has also stated that should the temperature begin to drop, it will take immediate remedial action before the temperature reaches 40°F to restore room temperature to normal. In the event the room temperature should fall below 40°F the applicant is required by operability Technical Specifications to declare the HPCS diesel generator inoperable. The staff finds this acceptable.

Some of the HPCS diesel generator engine-mounted piping and components are not designed to the Boiler and Pressure Vessel Code of the American Society of Mechanical Engineers (ASME Code) Section III, Class 3, requirements in accordance

with applicable SRPs. The applicant, by letter dated August 21, 1984, provided information on the design and fabrication of the above piping and components. The applicant has indicated in followup discussion with the staff that, except for items which were not available as Class 3 or B31.1, all engine-mounted piping and components are designed, installed, and tested to American National Standards Institute (ANSI) Std. B31.1 requirements. In addition all engine-mounted piping and components have been analyzed to seismic Category I requirements. The applicant concludes that piping and components, in accordance with the above criteria, are the equivalent of ASME Code Section III requirements in terms of system functional operability and inservice reliability. The staff concurs with the applicant and finds the engine-mounted piping and components for the HPCS diesel generator acceptable subject to confirmation of the above information.

In addition the applicant was asked to provide a description or a logic diagram for the HPCS diesel generator air starting system instrumentation and controls. The applicant by letter dated August 21, 1984 provided logic diagrams.

In the River Bend SER the applicant was requested to provide information on their program for monitoring the performance of the air dryers in the respected air starting systems of the standby diesel generators to ensure that starting air quality with respect to moisture is maintained. The applicant by letter dated March 5, 1985 provided additional information. The staff has reviewed the applicants submittal and finds it acceptable.

Section 9.5.6 in the River Bend FSAR contains reference to alarms in the compressed air starting systems to annunciate and indicate abnormal conditions. Also, FSAR Section 7.3 contains logic diagrams for the standby diesel generators' air start systems instrumentation and controls on which the above-mentioned alarms are not included. The applicant was asked to clarify the inconsistency. The applicant by FSAR Amendments 11 and 13 and letters dated August 21, 1984, and July 24, 1985, provided information to clarify the inconsistency.

The applicant had not provided FSAR drawings showing the locations of the standby diesel generator starting air instrumenation and control components. In FSAR Amendment 20, the applicant provided the information.

During the initial review, the staff could not conclude that the HPCS diesel generator air-start system capacity was capable of delivering five consecutive starts without recharging. By letter dated August 21, 1984, the applicant provided additional information on the design and capacity of this system. The applicant stated that the River Bend HPCS diesel generator air-start system was identical to the system installed at the Perry Nuclear Station. In addition, the applicant provided an extrapolation of data from actual air-start system tests at the Perry plant. On the basis of these data, the applicant concluded that the HPCS diesel generator air-start system has adequate capacity for more than five consecutive 10-second starts without recharging, assuming the lowest normal operating pressure of 215 psig. The staff evaluated the data provided by the applicant and concluded that the extrapolation is conservative, and that the capacity of the HPCS diesel generator air-start system is acceptable.

The applicant had not addressed the staff's concern regarding the lack of air filters on the HPCS diesel generator air-start system air compressor intake openings. By letter dated June 5, 1985, the applicant provided this information. The HPCS diesel generator air start compressor intakes include filters capable of removing particle size of 15-20 microns. This satisfies the staff's concern, and the staff concludes that the HPCS diesel generator air-start system is acceptable.

9.5.7 Emergency Diesel Engine Lubrication Oil System

In the River Bend SER the staff asked the applicant to confirm details of the standby diesel generator turbocharger drip lube circuit on the appropriate piping and instrumentation diagram (P&ID). The applicant, by letter dated March 5, 1985, provided this information on the appropriate P&ID.

At the time the SER was issued, the applicant had not provided sufficient information regarding the HPCS diesel generator lube oil system to support a complete staff review. The applicant also had not provided information on the frequency of test and calibration of the lube oil systems (standby & HPCS) instrumentation and controls. The applicant, by FSAR amendments __ and 21 and letters dated March 5, 1984 and August 21, 1984, provided the information. The staff has reviewed the submittals and finds acceptable the HPCS diesel generator

lube oil system including instrumentation and controls, and test and calibrations on an 18-month basis for the HPCS and standby diesel generators.

In the FSAR, the applicant identified the HPCS diesel generator lube oil system piping and components as not being designed, fabricated, and installed in accordance with ASME Code Section III, Class 3, requirements. The staff found this unacceptable. By letter dated August 21, 1984, the applicant stated that the above piping and components were designed in accordance with ANSI Std. B31.1 requirements (to the maximum extent practicable) and, in addition, had been pressure tested in accordance with the hydrostatic test parameters specified in ANSI B31.1. The applicant concluded that the design and testing of the HPCS diesel generator lube oil system piping and components to the above criteria would be the equivalent of ASME Code Section III, Class 3, with regard to functional operability and inservice reliability. The staff agrees with the applicant's conclusions and finds the design of the above HPCS diesel generator lube oil system piping and components acceptable subject to confirmation that the hydrostatic testing had been performed per ANSI B31.1. However, operatin up to 5% power is justified source similar systems are in operation at other nuclear plants and have demonstrated high reliability.

In the SER, the staff asked the applicant to clarify the purpose and operation of relief valves installed in the standby diesel generators lube oil systems. As shown on the piping and instrumentation diagram (P&ID), the relief valves would have bypassed an important pressure differential (high) alarm. By FSAR amendment, the applicant redesigned the system to eliminate the staff's concerns.

Therefore, the staff concludes that the standby and HPCS diesel generator lube oil system is acceptable subject to confirmation of the following item:

(1) the details of the standby diesel generator turbocharger drip lube circuit have been included on the appropriate P&ID

(2) the HPCS 6-gpm pump provides adequate lubrication of the turbocharger

(3) the turbocharger prelube circuit can function as shown on the P&ID

(4) this information has been included in the FSAR

The staff find that operation up to 5% power is justified, since similar systems are in operation at other nuclear plants and have demonstrated high reliability.

Therefore, the staff concludes that the diesel generator (standby and HPCS) combustion air intake and exhaust systems are acceptable.

Table 9.1 Conformance to NUREG/CR-0660 recommendations (revised from SER)

Recommendation	Conformance	Section
1. Moisture in air starting system	Yes	9.5.6 (SER)
2. Dust and dirt in diesel generator room	Yes	9.5.4.1 (SSER 2)
3. Turbocharger gear drive problem	Yes	8.3 (SER)
4. Personnel training	Yes	9.5.4.1 (SSER 2)
5. Automatic prelube	Yes	9.5.7 (SSER 2)
6. Testing, test loading, and preventive maintenance	Yes	9.5.4.1 (SER)
7. Improve the identification of root cause of failures	Yes	9.5.4.1 (SER)
8. Diesel generator ventilation and combustion air systems	Yes	9.5.8 (SSER 2)
9. Fuel storage and handling	Yes	9.5.4.2 (SER)
10. High temperature insulation	*	9.5.4.1 (SER)
11. Engine cooling water	Yes	9.5.5 (SER)
12. Concrete dust control	Yes	9.5.4.1 (SSER 2)
13. Vibration of instruments	Yes	9.5.4.1 (SSER 2)

*Explicit conformance is considered unnecessary by the staff in view of the equivalent provided by the design, margin, and qualification testing requirements that are normally applied to emergency standby diesel generators.

10 STEAM AND POWER CONVERSION SYSTEM

10.4 Other Features

10.4.6 Condensate Demineralizer System

NUREG-0737 II.B.3 - Post-Accident Sampling Capability

The staff has determined that the applicant met the criteria of Item II.B.3 of NUREG-0737. Criterion 2 which requires a procedure to estimate core damage remained as a confirmatory item to be completed prior to criticality. By letter dated May 13, 1985, the applicant provided additional information.

The applicant provided procedure COP-1050 for estimating core damage during accident conditions based on the generic Westinghouse Owners Group Core Damage Assessment Methodology dated March 1984.

Core damage estimates are based on utilizing postaccident sampling system measurements of fission product concentrations in primary coolant and in containment. Additional procedures are provided for estimating the extent of metal-water reaction based on measured hydrogen concentration in containment and for estimating the extent of core damage based on containment radiation monitors. Reactor vessel water-level and core exit thermocouple temperatures are used to establish if there has been adequate core cooling. This meets Criterion 2 and is, therefore, acceptable.

Thus, the staff concludes that the applicant's postaccident sampling system meets all the requirements of Item II.B.3 of NUREG-0737 and is acceptable. Confirmatory Item 50 can now be removed from the license.

11 RADIOACTIVE WASTE MANAGEMENT

11.2 Liquid Waste Management System

In the SER, the staff found the liquid waste management system acceptable. However, the applicant submitted a revision to this system in an FSAR amendment in its letter dated April 17, 1985. This revision describes design features to allow outside contractors to provide portable liquid waste self-contained disposable filter and demineralizer services when necessary or for special applications when the present liquid waste filter and demineralizer are not functional. In summary, the portable filter and demineralizer vessels will be located in a spare shielded cubicle in the radwaste building. Floor drains direct spills to the radwaste building floor drain collection tanks.

The staff has reviewed this modification and considers it acceptable with the following comment:

The applicant should describe the method(s) for disposal of the self-contained filters and demineralizers. The present system transfers spent resins and filter media to the solid waste processing system for stabilization and the overall solid waste process is controlled by an approved process control program. The applicant should describe the methodology for disposing of and classifying these "throw away" filter/demineralizer canisters. Also, the process control program referenced in Section 11.4 of this supplement should be revised to include the details for classifying and processing, as well as the administrative controls imposed for disposal of these items. It is mentioned only for emphasis that the disposal requirements of 10 CFR 61 and the Branch Technical Positions for solid waste disposal apply to these portable "throw away" filter/demineralizer canisters. This information should be submitted to the staff with a revised process control program (PCP) as discussed below in Section 11.4 of this supplement.

11.4 Solid Waste Management System

The SER in Section 11.4.2 identified as a licensing condition (License Condition 7) that solid waste cannot be processed until after NRC approval is granted of the applicant's solid waste process control program (PCP). In its letter dated January 7, 1985, the applicant submitted the PCP for staff review. The staff has conducted a limited review of the applicant's PCP and concludes that the applicant can, on an interim basis, process solid waste. The interim approval is granted based on the judgment that the applicant's PCP has included waste sampling and analysis controls that should ensure acceptable solid waste forms. However, because its review criteria for an acceptable PCP have recently been formulated, the staff has not yet reviewed the applicant's PCP against this new set of guidelines. The staff will send a copy of these guidelines titled, "Guidelines for Preparation of a Solid Waste Process Control Program," to the applicant under separate cover, for applicant review and use. A full review of the applicant's PCP will be made after the applicant has had time to modify its PCP (if appropriate) and resubmit it to the staff for review. Therefore, the applicant must revise its PCP and submit it for staff approval before operation after the first refueling outage.

Accordingly, an interim approval is granted of the applicant's PCP pending a future review and determination of any necessary changes.

11.5 Process and Effluent Radiological Monitoring and Sampling Systems

11.5.4 Process Monitoring and Sampling

The SER requested as Confirmatory Item 52 information pertaining to the design method employed to minimize iodine and particulate plateout in air sample lines and also to provide information on the capability for the sample monitors to measure postaccident activity concentrations as specified in TMI Action Plan Item II.F.1, Attachment 2.

The applicant, in its letter dated January 24, 1985, provided information in the FSAR describing the activity monitor ranges for the subject monitor. In addition, the applicant stated the sample lines are heat traced to prevent iodine vapor condensation on the tubing wall. Also, the lines are of stainless steel tubing, and flow straighteners are provided in process streams; although not explicitly conforming to the guidelines specified by ANSI Std. N13.1-1969 ("Guide to Sampling Airborne Radioiodine Materials in Nuclear Facilities"), they meet the intent.

The staff considers the steps taken by the applicant to minimize iodine and particulate plateout in sample lines to be appropriate. Confirmatory Item 52 is closed.

12 RADIATION PROTECTION

12.3 Radiation Protection Design Features

12.3.2 Shielding

As required in TMI Action Plan Item II.B.2, "Design Review of Plant Shielding Which May Be Used in Postaccident Operations," the applicant has provided a radiation and shielding design review that identifies the location of vital areas and equipment in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by radiation during operations following an accident resulting in a degraded core.

The plant shielding design report was reviewed to evaluate the ability to have access to vital areas necessary to operate essential systems required after a LOCA with significant core damage.

Vital areas that require continuous or frequent occupancy in order to control, monitor, and evaluate the accident were identified. In addition, the applicant identified potential maintenance activities that might become necessary during recovery and determined when after an accident such maintenance would be possible. For vital areas, the applicant has provided a person-rems, time, distance, and personnel occupancy study. The vital areas are the Operational Support Center, main plant exhaust duct effluent monitor grab sample area, postaccident sample station control panel and sample panel, health physics/chemistry laboratory, primary access point, main control room, and Technical Support Center.

Calculations of source terms and estimated postaccident dose rates used for shielding design are based on RGs 1.4 and 1.7, and the guidelines of GDC 19. The applicant has provided "radiation" maps that show access routes to postaccident vital areas, to be used as an administrative guide in controlling access and reducing personnel exposure during the course of an accident.

Systems containing high levels of radioactivity in a postaccident environment were identified but were found to be either irrelevant or negligible contributors of radiation dose following an accident.

The applicant's postaccident access and shielding study for River Bend Station shows that no personnel will be exposed to postaccident doses greater than GDC 19 dose rate guidelines of 5 rem whole body or its equivalent to any part of the body for the duration of the accident.

On the basis of its review, the staff has concluded that the applicant has performed a radiation and shielding design review for vital area access in accordance with TMI Action Plan Item II.B.2 and Confirmatory Item 54 is closed.

12.5 Operational Radiation Protection Program

12.5.1 Organization

The Backup Radiation Protection Manager meets the positions in NUREG-0731 Item II.A.2 and therefore is acceptable and Confirmatory Item 55 is closed.

13 CONDUCT OF OPERATIONS

13.1 Organizational Structure of Applicant

13.1.2 Corporate Organization

Because the staff is concerned about the possible lack of hot operating experience among the operators on shift at newly licensed reactor power plants, it has evaluated the operating experience on shift proposed by the applicant.

13.1.2.1 Operating Experience on Shift

Dialogue with the industry was begin late in 1983 to find a way of ensuring that each operating shift at a newly licensed plant had at least one senior operator with previous hot operating experience. On February 24, 1984, an Industry Working Group representing utilities with nuclear power plants under construction or ready for operation presented a proposal to the staff on the amount of previous operating experience considered to be the minimum desirable on each shift and how that experience could be obtained. On June 14, 1984, the staff accepted the industry proposal with certain clarifications. Information regarding the staff action was forwarded to the industry as Generic Letter 84-16, dated June 27, 1984. The objective is that, at the time of initial criticality, each operating shift will have at least one senior operator with a minimum of 6 months of hot operating experience on a similar type plant, including startup/shutdown experience and at least 6 weeks' experience operating above 20% power. However, for plants in the late stages of licensing with insufficient time to meet the objective, the temporary use of experienced shift advisors is acceptable. The minimum experience level for shift advisors is 4 years of power plant experience (including 2 years of nuclear power plant experience) and 1 year of hot operating experience as a senior reactor operator, if found suitably qualified) on a large commercial nuclear power plant of the same type as the plant at which they will work. All shift advisors are to be trained on the systems, procedures, and Technical Specifications of the plant for which they are to provide advice and they are to be certified to the NRC as being qualified to act as shift advisors.

The applicant's latest submittals on operating experience are dated March 7, April 11, and May 28, 1985; a meeting between the applicant and the staff was held on May 14, 1985, and additional information was provided. The applicant has four licensed senior operators with enough BWR operating experience to satisfy the requirements of Generic Letter 84-16. The applicant has also identified three other individuals with BWR operating experience who could be used as shift advisors until additional senior operators who do meet the requirements of the generic letter can be licensed. The staff has reviewed the applicant's submittals and its findings are discussed below.

In addition, since the applicant does not now have senior reactor operators on each shift who meet the minimum guidelines for hot operating experience, the staff will condition the operating license to require shift advisors until such time as the requisite experience has been obtained.

13.1.2.2 Shift Advisor Program

By letters dated March 7, April 11, and May 28, 1985, the applicant has submitted information regarding the shift advisor program at River Bend. The staff has reviewed this information for conformance to Generic Letter 84-16. The review has covered four main areas: shift advisor experience, the shift advisor training program, the procedure used to define shift advisor duties and responsibilities, and other matters pertaining to the use of shift advisors.

(1) Shift Advisor Experience

Two prospective shift advisors amply meet the requirements of Generic Letter 84-16 and may participate in the River Bend shift advisor program. All have well over 4 years of power plant experience (including well over 2 years of nuclear plant experience), and all have had well over 1 year as a senior operator at a large operating BWR.

A third prospective shift advisor would also meet the requirements of Generic Letter 84-16, except that he has only 11 months (rather than at least 12 months) of on-shift SRO experience at a large operating BWR. However, this individual also has a bachelor's degree in nuclear engineering and has 14 months of on-shift Shift Technical Advisor (STA) experience at a large operating BWR, which more than compensates for the 1-month shortfall in on-shift SRO time. The staff considers the third prospective shift advisor to be qualified to participate in the River Bend shift advisor program.

(2) Shift Advisor Training Program

The shift advisor training program is patterned after the systems training course described in FSAR Section 13.2.1.1.2, the simulator course described in FSAR Section 13.2.1.1.3, and the general employee training described in FSAR Section 13.2.1.2.3. In addition, the simulator segment will include training in station procedures; the applicant should ensure that the Technical Specifications are also covered. The staff finds the applicant's shift advisor training program acceptable, assuming that it includes, or will include, familiarization with the River Bend Technical Specifications.

(3) Shift Advisor Procedure

The duties and responsibilities of the shift advisor are described in River Bend procedure TP-85-02. This procedure establishes experience/training criteria, log-keeping and shift-turnover requirements, and other detailed duties and responsibilities of the shift advisor position. The main responsibility of the shift advisor will be to evaluate plant conditions and provide advice to the Shift Supervisor during startup testing, low-power testing, and power ascension.

Step 6.1 of of procedure TP-85-02 (draft Rev. 0) states, in part, that shift advisor candidates shall have a minimum of "six months on shift" as a licensed SRO or RO at an operating plant of the same type (i.e., BWR). In order for this procedural requirement to agree with Generic Letter 84-16, it should read "one year on shift."

The staff has reviewed draft Revision 0 of TP-95-02 and, with the exception of the one change described above, finds it acceptable.

(4) Additional Shift Advisor Issues

Plant management will review the performance of each shift advisor as part of the monthly appraisal of overall shift performance. This is acceptable to the staff.

All members of operating shift crews will be responsible for familiarizing themselves with the shift advisor procedure. This is acceptable to the staff.

The prospective advisors have passed a River Bend health screening examination. This is acceptable to the staff.

13.1.3 Nuclear Administration

Gulf States Utilities (the applicant) has made several organizational changes. Some of these changes are not significant because they are essentially title changes. Some other changes are, however, significant.

Revised Figure 13.1 shows the organization of the nuclear project. Of significance, the Senior Vice President - River Bend Nuclear Group, reports directly to the Chairman of the Board. Thus, the senior corporate officer with exclusive nuclear responsibility is highly placed within the organization. Four positions report to the Senior Vice President - River Bend Nuclear Group. These are:

- Vice President - Safety and Environment
- Vice President - River Bend Nuclear Group
- Manager - Quality Assurance
- Manager - Project Control

The Manager - Project Control position is related to construction and will not be considered further in this evaluation except to note that he now reports one management level higher than before. The Manager - Quality Assurance remains in the same reporting position as before, but his title has been upgraded. The Vice President - Safety and Environment is a new position. The incumbent is responsible for environmental services, serves as Chairman of the Nuclear Review Board (i.e., the offsite committee), and is the individual to whom the Independent Safety Engineering Group (ISEG) reports. The organizational change involving ISEG meets the intent and requirements of TMI Action Plan Item I.B.1.2, in that this group reports to a corporate official who is not in the management chain for power production.

The Vice President - River Bend Nuclear Group is responsible for both line (plant operation) and direct support functions. There are four positions reporting to this Vice President. These are:

- Plant Manager
- Manager - Engineering, Nuclear Fuels, and Licensing
- Manager - Projects Planning and Coordination
- Manager - Administration

The Manager - Administration is responsible for four functions: training, emergency planning, security, and support services. The title has been changed from Vice President (SER Figure 13.1) to Manager (SSER 2 Figure 13.1) and the environmental services function has been transferred to the Vice President - Environmental Services. It is noted that the somewhat unusual organization arrangement whereby security is not administratively under the Plant Manager is retained. This was found to be acceptable before. The applicant now proposes to delete from the responsibilities of the onsite Facility Review Committee (FRC) responsibility for reviewing the security plan and implementing procedures. This proposed change coupled with the unusual organization removes all review of security plans and procedures from those organizations charged with safe plant operation. This is only acceptable if the Plant Manager's concurrence is required on the physical security plan, its implementing procedures, and all changes thereto before their implementation. For similar reasons, the Plant Manager's concurrence shall be required on the emergency and fire protection plans, implementing procedures, and changes thereto, before implementation.

The Manager - Projects Planning and Coordination, a new position under the Vice President - River Bend Nuclear Group, is assigned the responsibility for the outage management system and for continuing interface with the architect-engineer and nuclear steam system supplier.

The staff concludes that the organization changes proposed by the applicant are acceptable, provided that there is a specific requirements that the Plant Manager will concur in the security, emergency and fire protection plans, implementing procedures and changes thereto before implementation.

13.1.4 Station Organization

The organization under the Plant Manager has been changed so that there are now four positions that report to the Plant Manager. These are:

- Assistant Plant Manager - Operations
- Assistant Plant Manager - Technical Services
- Assistant Plant Manager - Maintenance and Materials
- Supervisor - Radiological Programs

The position of Superintendent - Startup and Test also reports to the Plant Manager, but only until the plant reaches commercial operation. The revised organization provides direct access to the Plant Manager for the individual responsible for radiological health and safety. It should be noted, however, that the radwaste and chemistry functions are retained under the direction of the Assistant Plant Manager - Operations.

The Assistant Plant Manager - Maintenance and Material is responsible for the mechanical, electrical, and instrument and control craft groups, as well as for purchasing and materials. This is a new position, but the functions and responsibilities grouped under it are logically determined.

The shift organization indicates a minimum of 14 personnel. Included in this total are 2 radiation protection technicians, 1 chemistry technician, and 1 nuclear test technician. There are also 5 nonlicensed operators, one of whom is a radwaste operator. The applicant has proposed to have 5 licensed operators (2 Senior Reactor Operators, SROs, and 3 Reactor Operators, ROs) on shift

but not to have a Shift Technical Advisor (STA), provided that one of the SROs has had sufficient additional training to qualify as an STA. This is conceptually acceptable. The applicant has also committed to have a separate STA on shift if neither of the 2 SROs has had sufficient additional training to act as STA. In this latter instance, it is proposed that one of the 3 RO positions would not have to be filled. This would keep minimum shift manning at 14, with 2 SROs, 3 ROs, and 1 STA. Since this alternate proposal appears to satisfy TMI Action Plan Item I.A.1.1, it is considered an acceptable alternative.

The résumés of key personnel have been reviewed. On the basis of this review, it is concluded that key members of the operating staff meet the requirements of Regulatory Guide (RG) 1.8 (ANSI/ANS Std. 3.1-1978). This satisfactorily resolves Confirmatory Issue 56 of the River Bend SER.

On the basis of this supplemental review, the staff has determined that changes to applicant organization and personnel qualifications meet regulatory guidance.

13.2 Training

The applicant has added a section (13.2.1.3.1) to the FSAR which describes the training for STAs. The applicant states that this training meets the intent of TMI Action Plan Item I.A.1.1 for STA training. Although the times allocated to various aspects of the training vary slightly from the periods delineated in the TMI Action Plan (NUREG-0737 Appendix C), the applicant's program appears to cover all aspects of the required training for STAs. The applicant also describes an STA retraining program and links this to a requalification training program for those SROs who are cross-trained as STAs.

The applicant has described the requalification training program. This description commits to the items delineated in 10 CFR 55 (Appendix A) and in the H. R. Denton letter of March 28, 1980. The commitment to requalification training thus meets the regulatory requirement of 10 CFR 50.54 and NUREG-0737 Items I.A.2.1 and II.B.4.

On the basis of the review of the supplemental applicant submittal, the staff concludes that the applicant's training commitments remain acceptable.

Offsite Fire Department Training

In the SER, the staff stated that training for the fire protection staff and for offsite fire departments was not firm and was therefore subject to confirmatory review. FSAR Amendment 13 delineated how the fire prevention staff would be trained. The applicant's letter of October 22, 1984, committed to specific, annual training of offsite fire departments (including basic radiation protection), the use of personal dosimetry, plant familiarization (including fire protection systems and hazards), and fire-fighting procedures (including entry and exit from the plant). The October 22, 1984, letter also stated that these commitments would be included in an FSAR amendment. These changes and commitments that the applicant has made are acceptable. This resolves SER Confirmatory Issue 58.

13.3 Emergency Preparedness

13.3.1 Background

The SER provided the staff's review and evaluation of the River Bend Station Radiological Emergency Plan (Plan), including FSAR Amendment 11 and supplemental information and commitments in letters dated October 8, 1983, and February 16, 1984. In SER Section 13.3.3, the staff concluded that the Plan will provide an adequate planning basis for an acceptable state of onsite emergency preparedness when those items requiring resolution and those items committed to by the applicant are satisfactorily completed.

After the SER was issued, the applicant continued to upgrade its emergency planning program and submitted FSAR Amendments 13, 15, and 16 (June 1984, November 1984, and February 1985, respectively). On August 14, 1984, and February 5, 1985, the applicant responded to the items identified by the staff in the SER, and, in addition, furnished information that the staff had requested.

The staff has completed its review and evaluation of the FSAR through Amendment 16 and the applicant's responses of August 14, 1984, and February 5, 1985. The results of this evaluation are given in Section 13.3.2 below under the same format used in the SER. Section 13.3.3 provides the staff's conclusions.

An onsite appraisal of the applicant's implementation of its emergency preparedness program was conducted between December 3 and 14, 1984. The appraisal was conducted in seven general areas: administration, organization, facilities and equipment, training, procedures, coordination with offsite support groups, and drills, exercises, and walkthroughs. Appraisal results are documented in NRC's Office of Inspection and Enforcement (IE) Inspection Report No. 50-458/84-35, dated March 28, 1985. NRC Region IV will conduct followup appraisal(s) to ensure that all identified deficiencies are corrected.

A full participation exercise of the River Bend Station Emergency Plan was conducted at the River Bend site on January 16, 1985. The exercise tested the capabilities of the applicant's onsite and offsite emergency support organizations to respond to a simulated accident scenario resulting in a major radioactive release. The exercise was integrated with a test of the emergency plans of the State of Louisiana and the parishes of West Feliciana, East Feliciana, Pointe Coupee, East Baton Rouge, and West Baton Rouge. NRC's findings, which are documented in IE Inspection Report No. 50-458/85-03, dated March 29, 1985, show that the applicant demonstrated an adequate state of onsite emergency preparedness.

13.3.2 Emergency Plan Evaluation

13.3.2.1 Assignment of Responsibility (Organizational Control)

(1) Letters of Agreement

By letter dated August 14, 1984, the applicant provided an agreement letter with Our Lady of the Lake Regional Medical Center, dated April 9, 1984. The letter describes: (1) the capabilities of the medical center for treating contaminated patients from River Bend Station on a 24-hr/day basis, (2) training to be provided by the applicant for medical center personnel, and (3) a list of medical

and emergency equipment. Medical support is discussed further in Section 13.3.2.12 of this supplement.

With regard to the letter of agreement with Illinois Central Gulf Railroad (ICGR), in its response of August 14, 1984, the applicant explained that sufficient track was purchased so that ICGR is abandoning the track that traverses the site in a northwest-southeast direction. Thus, the applicant has direct control over access to the site via the railroad and no longer requires an agreement letter with ICGR to provide this control.

In its February 5, 1985, response, the applicant provided letters of agreement with Stone and Webster Engineering and General Electric Company (GE's letter, amended December 11, 1984, confirms the agreement pending formal contract agreement).

The applicant has obtained a letter of agreement with the State of Mississippi dated May 24, 1985. The applicant advised the staff that this letter would be appended to the Plan in the next FSAR amendment.

The staff finds the above portions of the applicant's Plan adequate.

13.3.2.2 Onsite Emergency Organization

(1) Secondary Assignment of Shift Supervisor

Information on the Shift Technical Advisor (STA) function provided by the applicant on October 28, 1983, has been incorporated into the Plan. The Plan specifies that the STA function is a collaterally shared responsibility of the Shift Supervisor and the control operations foreman (COF) as shown in Table 13.3-5 and Figure 13.3-7 of the Plan. The Shift Supervisor and the COF are both Senior Reactor Operators who will be trained in accordance with the April 30, 1980, INPO (Institute of Nuclear Power Operations) guidance document provided under NUREG-0737, Item I.A.1.1, "Shift Technical Advisor." The Shift Supervisor will be primarily responsible for emergency direction and control. The COF will be primarily responsible for technical support in plant system engineering, repair, and corrective actions. The Shift Supervisor or the COF, and hence a qualified STA, will be in the control room at all times. In addition, in Section 13.2.1 of the SER, the staff concluded that the training for licensed plant staff personnel meets regulatory requirements. Furthermore, the shift staffing shown in Table 13.3-5 of the Plan conforms to Table B-1 of NUREG-0654 (Table 2 of Supplement 1 to NUREG-0737). The staff finds this portion of the applicant's Plan adequate.

(2) Availability Requirement of Recovery Manager and Other Personnel

By letter dated August 14, 1984, the applicant provided the results of its study of residential patterns to determine response capability as suggested in Table B-1 of NUREG-0654. On the basis of these results and FSAR Amendment 15, the staff finds that the applicant's Plan meets the guidance criteria of Table B-1 under normal weather and traffic conditions. Under severe weather or heavy traffic conditions, the applicant specifies that the 30-minute responders could be available in 45 minutes. To implement the 60-minute augmentation criteria during these conditions, all but six individuals would be available in 60 minutes. Of

these six individuals, five would be available in 75 minutes and one, an alternate radiation protection technician, would require about 90 minutes to be available at the site. The Plan indicates that the entire emergency organization, including a primary person and two alternates for each key position, could be available within 60 minutes during fair weather and light traffic. The staff finds this portion of the applicant's Plan adequate.

(3) Primary and Alternate Spokespersons

FSAR Amendment 15 (Table 13.3-5 and Section 13.3.6.2.1) identifies the Senior Vice President External Affairs (Gulf States Utilities (GSU) Public Spokesperson) as the primary spokesperson and the Administrator of Louisiana Communications as the alternate spokesperson. The staff finds this portion of the applicant's Plan adequate.

13.3.2.3 Emergency Response Support and Resources

(1) Dispatch of a Utility Representative

FSAR Amendment 15 provides for the dispatch of a technical representative to each of the five parish EOCs during a Site Area or General Emergency in order to ensure continuity and coordination among the utility, State, and affected parishes. The staff finds this portion of the applicant's Plan adequate.

(2) Review of Proposed Change To Replace the Mutual Assistance Plan

The Mutual Assistance Plan between Gulf States Utilities Company, Arkansas Power and Light Company, Louisiana Power and Light Company, Mississippi Power and Light Company, and Middle South Services, Inc., contained in Appendix B to the Plan is to be replaced by the "Nuclear Power Plant Emergency Response Voluntary Assistance Agreement," which is advocated by INPO. An appropriate Plan change will be made. Also, copies of the INPO Emergency Resources Manual will be available in the Technical Support Center and Emergency Operations Facility. The staff finds this proposed change to the applicant's Plan adequate.

13.3.2.4 Emergency Classification System

(1) Emergency Action Levels

Following discussions with the applicant in May 1984, Table 13.3-1 of the Plan was revised by FSAR Amendments 13 and 15. The staff completed its review of Table 13.3-1, Amendment 15, dated November 1984, and on February 22, 1985, requested that the applicant provide additional information and clarification on certain EALs that were previously discussed with the applicant. On March 29, 1985, the applicant provided the additional information and clarification that were requested and committed to make a further minor revision to the EAL scheme in a future FSAR amendment. The staff finds this portion of the applicant's Plan adequate.

13.3.2.5 Notification Methods and Procedures

(1) Emergency Implementing Procedures

On October 3, 1984, the applicant submitted its approved EIPs for the staff's review. The review of EIPs was conducted during the onsite appraisal of the

applicant's implementation of its emergency preparedness program on December 3-14, 1984 (see IE Inspection Report No. 50-458/84-35). The staff finds this portion of the applicant's Plan adequate.

(2) Notifying Augmentation Personnel

Notification of the applicant's emergency organization augmentation personnel located in Beaumont, Texas, is addressed in Section 13.3.2.13 of this supplement. This confirmatory item is considered closed.

(3) Alert and Notification System

A general description of the final system configuration, siren control signals, and system communications has been provided and included in FSAR Amendment 15. On February 5, 1985, the applicant provided information on alert monitoring radios to be placed in special facilities as a secondary means of notification within the 10-mile emergency planning zone (EPZ). This information will be included in a future amendment to the FSAR.

On April 19, 1985, the applicant submitted an "Operational Siren Certification Report." The report includes a complete system description; installation information; means for alerting special facilities, unpopulated areas, and the transient population; a design report summary, and a schedule for completing the system and testing it.

The applicant informed the staff that all sirens are now installed and that the operability of the entire system was tested on May 29, 1985. The results of this test will be furnished to NRC Region IV. The applicant plans to submit a full report on the total alert and notification system (ANS) in accordance with the FEMA 43 procedure in the near future.

NRC Region IV has identified the installation and operability testing of the ANS as an item to be completed before fuel load. Accordingly, Region IV will provide confirmation in an inspection report that the ANS has been installed and operability tested. On the basis of its review of the Plan and the applicant's submittal of April 19, 1985, the staff finds this portion of the applicant's Plan adequate. This item is closed.

(4) Notifying the Public

FSAR Amendment 15 provided additional information on the administrative capability of local authorities to promptly alert the public. A dedicated telephone system permits plant personnel to notify the five parishes and State agencies simultaneously and within 15 minutes, on a 24-hr/day basis, of any emergency classification and recommended protective actions for the public. On reaching a decision to implement a protective response, each Parish Police Jury President, through the Civil Defense Director, will first ensure that an Emergency Broadcast System message coordinated with other parishes is ready to be broadcast. Control consoles in each of the five parish Emergency Operation Centers (EOCs) allow activation of sirens and alert monitoring radios in each respective parish. Each of the five parishes has an emergency plan compatible with the State of Louisiana emergency plan which will be exercised periodically. Training will be provided on the offsite plans. The EAL configuration in Table 13.3-1 of the Plan provides the utility interface with State and local officials for offsite

response under the four emergency classifications. On an annual basis, State and local authorities will review their interface with the applicant with regard to offsite response necessary (under the four emergency classes as shown in the EAL scheme in Table 13.3-1) for the protective action decisionmaking process. The protective action decisionmaking process (onsite and offsite) utilizes plant status, core/containment conditions, offsite monitoring results, EPA protective action guides, protective action sections (subareas of the 10-mile EPZ), EAL table, and evacuation time estimates in the Plan. The staff finds this portion of the applicant's Plan adequate.

13.3.2.6 Communications

(1) Testing the Health Physics Network and the Emergency Notification System

Section 13.3.7.3.2.3 of the Plan has been revised to include testing of the health physics and emergency notification systems between the control room, TSC, EOF, NRC Headquarters, and NRC Region IV on a monthly basis. The staff finds this portion of the applicant's Plan adequate.

13.3.2.7 Public Information

(1) Emergency Information Brochure

The staff has received a copy of the final public emergency information brochure. The brochure contains the information specified in the guidance criteria of NUREG-0654. FEMA will provide an evaluation of the brochure in the process of its review of offsite plans. The staff finds this portion of the applicant's Plan adequate.

13.3.2.8 Emergency Facilities and Equipment

(1) Interim Facilities

By letter dated February 16, 1984, the applicant committed to submit a new appendix to FSAR Section 13.3 that describes the capabilities of the interim facilities. In lieu of submitting a new appendix to the Plan, the applicant changed Section 13.3.6 identifying those automated, diagnostic functions in the TSC and EOF which may not be fully functional until February 1986. Table 13.3-16 to the Plan specifies the primary and backup (secondary) systems for the emergency response information system (SPDS), digital radiation monitoring system - automated dose assessment system (MIDAS), and the meteorological information system. The applicant specifies that the secondary systems are provided so that the ERFs can effectively support an emergency. The ERFs were reviewed during the onsite appraisal in December 1984, and were utilized during the full participation emergency preparedness exercise on January 16, 1985. The staff finds this portion of the applicant's Plan adequate and also finds that, on an interim basis, the ERFs are capable of supporting an emergency response effort in the event of an emergency at River Bend. Therefore, this outstanding issue is closed for the SER. However, as indicted in the SER, the staff will conduct a post-implementation appraisal of the ERFs in accordance with Supplement 1 to NUREG-0737 on a schedule to be developed between the applicant and the staff.

(2) Meteorological Monitoring Program

The staff has reviewed the meteorological monitoring program presented in Sections 13.3.5.2 and 13.3.6.3 and Table 13.3-8 of the Plan and has conducted an onsite appraisal of its implementation. The staff's evaluation of the adequacy of the applicant's emergency response meteorological monitoring program, as presented in the Plan, and the implementation of the program is provided in IE Inspection Report No. 458/85-05. The staff considers this item closed.

(3) Lists of Medical and Radiological Equipment and Supplies

Appendix E to the Plan has been revised and now provides a list of medical and radiological equipment and supplies to be stored and used at West Feliciana Parish Hospital and Our Lady of the Lake Regional Medical Center. The staff finds this portion of the applicant's Plan adequate.

13.3.2.9 Accident Assessment

(1) Dose Assessment Methodology

Three methods for assessing the potential and actual consequences of a release of airborne radioactivity are described in the Plan. These consist of a computerized dose assessment method, which is the primary method, and two backup hand calculational dose assessment methods.

The computerized system, termed the Online Dose Assessment System (ODAS), receives effluent monitor data from the radiation data processing subsystem, meteorological information from the onsite meteorological tower, and isotopic composition data from multichannel analyzer input. These data are used for accident assessment and dose projection calculations using a model which conforms to the Class A model described in Appendix 2 of NUREG-0654, Revision 1. The model uses a blend of equations from RGs 1.111 (Revision 1) and 1.145 (Revision 1). The ODAS can compute and plot contour lines of equal disperion or dose on a site map based on the last 10-minute average of meteorological data recorded. Several alternative approaches are available to input release rates, isotopic data, and meteorological data.

An alternative manual calculation procedure is provided, via EIP-2-024, using a programmed electronic calculator with a printer. If both computer and calculator are not available, a third, totally manual method is provided in EIP-2-024 to calculate doses. The last method uses information from EPA's Manual of Protective Action Guides to convert concentrations of radionuclide to dose rate. The applicant has described methods by which the doses to the relevant target organs of individuals in the vicinity of the site can be estimated. The Plan also includes a manual procedure to assess the possible impact of a potential release to the liquid pathway (i.e., the Mississippi River). The applicant's dose assessment methods provide an adequate planning basis for emergency preparedness purposes.

Accident conditions of radiation levels in containment will be indicated by high range containment area monitors. Radioactive material available for release from the containment can be estimated using the readout from these monitors in conjunction with the graphs in Figures 13.3-25 and 13.3-26 of the Plan, relating

area monitor reading in containment versus time for the following accident situation radioactive releases: 100% gap activity, 100% coolant activity, and 1, 10, and 100% fuel inventory. Information from the high-range containment monitors is included in offsite dose assessment and is also incorporated in the EAL scheme for classifying Site Area and General Emergencies.

The staff finds this portion of the applicant's Plan adequate.

(2) Procedures for Radiological Sampling and Monitoring

On October 3, 1984, the applicant submitted approved EIPs to the staff. EIP-2-013 and EIP-2-014 provide instructions to the monitoring teams for inplant, onsite, and offsite radiological monitoring, respectively. These EIPs will be reviewed during the health physics preoperational inspection program. The staff finds this portion of the applicant's Plan adequate.

(3) Detection and Measurement of Radioactivity in Liquid Effluents

Section 13.3.3.2.2 of the Plan has been revised and now provides a general description of the applicant's methods for handling potential releases via the cooling tower blowdown and liquid radwaste effluent lines. These lines have radiation monitors that detect the radiation level in the blowdown to the Mississippi River and will alarm in the control room for any level above pre-established setpoints. EIP-2-024, "Offsite Dose Calculation-Manual Method," provides a method for projecting doses resulting from liquid releases. The EIPs will be reviewed during the health physics preoperational inspection program. The staff finds this portion of the applicant's Plan adequate.

13.3.2.10 Protective Response

(1) Manual Method of Accountability

Section 13.3.4.2.2.8 of the Plan has been revised to include a description of a manual badge exchange system that will be used to perform accountability in the event the security access control system is inoperative. The staff finds this portion of the applicant's Plan adequate.

(2) Classification of Emergencies and Protective Action Recommendations

The applicant has incorporated the guidance of Appendix 1 of NUREG-0654 into Table 13.3-1 (EAL scheme) of the Plan and EIP-2-007, "Protective Action Recommendation Guidelines." The staff finds this portion of the applicant's Plan adequate.

(3) 30-Minute Accountability for All Persons On Site

Section 13.3.5.4.1.1.3.4 of the Plan has been revised to specify accountability of all onsite individuals within 30 minutes of the declaration of a Site Area or General Emergency. In addition, should the Emergency Director determine that a protected area evacuation is required for other classes of emergency, the accountability will be accomplished within 30 minutes of the evacuation order. The staff finds this portion of the applicant's Plan adequate.

13.3.2.11 Radiological Exposure Control

(1) Exposure Limits for Medical Personnel

In correspondence dated February 5, 1985, the applicant specified that exposure limits for ambulance drivers are in accordance with the Louisiana Radiation Regulations, and by FSAR Amendment 16 revised the Plan accordingly. The staff finds this portion of the applicant's Plan adequate.

13.3.2.12 Medical and Public Health Support

(1) Emergency Medical Assistance Plans

By letter dated August 14, 1984, the applicant submitted the emergency medical assistance plan (EMAP) and the Decontamination and Treatment of the Radioactivity Contaminated Patient Manual of West Feliciana Parish Hospital and Our Lady of the Lake Regional Medical Center. The submittal contains a description of the hospitals' capabilities and agreement letters between Our Lady of the Lake Regional Medical Center, Jackson Rescue Unit, West Feliciana Parish Hospital, and Radiation Management Corporation (RMC) and the applicant. The submittal also includes agreement letters between RMC and the Hospital of the University of Pennsylvania and Northwestern Memorial Hospital. By FSAR Amendment 15, the applicant incorporated the EMAP into the Plan by reference. Appendix C to the Plan lists the EMAP as a supporting emergency plan. Controlled copies of the supporting emergency plans are maintained in the TSC and EOF. The staff finds this portion of the applicant's Plan adequate.

(2) Letters of Agreement

FSAR Amendment 13 provided letters of agreement with the Jackson Rescue Unit and West Feliciana Parish Hospital. The staff finds this portion of the applicant's Plan adequate.

13.3.2.13 Recovery and Reentry Planning and Postaccident Operations

(1) Coordination of Emergency Plans

By letter dated August 14, 1984, the applicant furnished additional information on the relationship between the River Bend Nuclear Group (RBNG) and GSU's headquarters. The applicant specifies that GSU headquarters does not provide support as previously detailed in FSAR Section 13.3.4.3.1 and Figure 13.3-11. The Plan has been revised to show that the RBNG is organized to support emergencies and provide long-range support during the recovery phase. Interface may be required between the Recovery Manager (Senior Vice President - RBNG), and GSU's Chief Executive Officer for authorization of funds above the Recovery Manager's authorized level. However, according to the Plan, GSU's Approvals and Authorization Procedures are in place to support this interface. The GSU Treasurer and Controller will manage funds required by RBNG during the emergency and recovery phases. In addition, the Licensing Support Coordinator (Beaumont, Texas) previously referenced in FSAR Table 13.3-5 is within the RBNG but is no longer a member of the emergency organization. The Joint Information Center (JIC) is operated by the JIC Director. The primary spokesperson within the emergency organization is the Vice President - External Affairs located in

Beaumont, Texas. However, the Administrator of Louisiana Communications (JIC Director) is located in Baton Rouge and will serve as the alternate spokesperson until he is relieved by the primary spokesperson. Primary and backup communications exist between River Bend and the GSU corporate office. EIP 2-006 provides for notification of the JIC Director by a pager system at the Notification of Unusual Event level.

An Emergency Communications Staff Activation and Functions Procedure (EIP-2-023) describes the functions of the GSU primary spokesperson and his alternate when interfacing with RBNG, local, and State public information personnel and the media. To ensure that the necessary coordination and interface exists among RBNG and local and State plans and procedures, the Recovery Manager will manage appropriate emergency implementing procedures with offsite authorities.

The staff finds this portion of the applicant's Plan adequate.

13.3.2.16 Responsibility for the Planning Effort: Development, Periodic Review, and Distribution of Emergency Plans

(1) Cross-Referencing the Plan and Emergency Implementing Procedures

Revised Table F-2 of Appendix F to the Plan includes a cross-reference between the EIPs and the section of the Plan that is implemented by each EIP. The staff finds this portion of the applicant's Plan adequate.

13.3.3 Conclusions

On the basis of the staff's review of the applicant's Plan, the staff concludes that the state of onsite emergency preparedness provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency during operation up to 5% of rated power.

The staff's conclusions with regard to offsite emergency plans and preparedness will be provided in a future supplement to the SER in support of full-power operations.

13.4 Operational Review

The organizational changes made by the applicant have resulted in changes in the onsite Facility Review Committee. The new composition of the FRC is as follows:

- Assistant Plant Manager - Technical Services, Chairman
- Assistant Plant Manager - Maintenance and Materials
- Assistant Plant Manager - Operations, Radwaste, and Chemistry
- General Operations Supervisor
- Reactor Engineering Supervisor
- Supervisor - Radiological Programs

There are also two nonvoting members on the onsite review committee: the Director, Operations QA and the Plant Services Supervisor, who acts as Secretary.

The committee composition appears to provide expertise or access to expertise in all required areas. The quorum is established as the Chairman (or designated alternate) and four members, of whom no more than two are alternates.

The review responsibilities for procedures are proposed to be that the FRC reviews all general administrative procedures. All other procedures are reviewed by the department responsible for their preparation (a peer review system). Additionally, cross-discipline reviews are done as required. Procedures are approved by either the Plant Manager or by one of his direct assistants, e.g., Assistant Plant Managers. This review plan concentrates the efforts of the FRC on the broader procedures which establish programmatic controls and allows detailed technical review by technical groups.

The makeup of the offsite committee, the Nuclear Review Board (NRB), has also changed. NRB composition is:

- Vice President - Safety and Environment, Chairman
- Vice President - River Bend Nuclear Group, Vice Chairman and Member
- Executive Vice President - External Affairs, Member
- Manager - Design Engineering, Technical Services Department, Member
- Manager - Engineering, Nuclear Fuels and Licensing, Member
- River Bend Station Plant Manager, Member
- Assistant Plant Manager - Operations, Radwaste and Chemistry, Member
- Manager - Quality Assurance, Member
- Manager - Administration, Member
- Director - Nuclear Plant Engineering, Member
- Director - Nuclear Fuels Design and Safety Analysis, Member
- Director - Nuclear Licensing, Member

This composition appears to contain or to have readily available expertise in all required areas. The quorum is the Chairman or the Vice Chairman and six members including no more than two alternates. This means that a majority of the NRB will be present in order to conduct a meeting. Also, individuals with line responsibility for power production are a minority on this committee.

The ISEG has been changed organizationally so that the ISEG reports to the Vice President - Safety and Environment. This appears to meet the requirements and intent of TMI Action Plan Item I.B.1.2.

The staff finds that the changes in review and audit meet SRP Section 13.4 and are acceptable.

13.5 Station Administrative Procedures

13.5.2 Operating, Maintenance, and Other Procedures

13.5.2.2 Operating and Maintenance Procedures Program

In SER Section 13.5.2.2, the staff described the review and approval of the applicant's operating and maintenance procedures program through FSAR Amendment 11. A letter from W. J. Cahill, Jr., to H. R. Denton, dated February 20, 1985, transmitted FSAR Amendment 16, which included changes made by the applicant to FSAR Section 13.5, "Procedures." The staff reviewed these

changes and determined that the applicant's operating and maintenance procedures program continues to meet the relevant requirements of 10 CFR 50.34, and remains consistent with RG 1.33, ANSI Std. N18.7-1976/ANS Std. 3.2, and NUREG-0800, Standard Review Plan, Section 13.5.2, "Operating and Maintenance Procedures."

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

SER Section 13.5.2.3 described the review of the River Bend Station (RBS) Procedures Generation Package (PGP) and identified one item (indicated as Confirmatory Item 60 in the SER) that had to be completed before the applicant's program for developing procedures could be approved. This item was the identification and justification of safety-significant differences between the RBS plant-specific technical guidelines and the NRC-approved BWR Owners Group guidelines. These differences and justifications were provided to the staff in a letter from J. E. Booker to H. R. Denton, dated January 15, 1985. Supplemental information was provided to the staff on February 11, 1985.

The staff used the plant-specific procedures to evaluate the justification for each deviation from the generic technical guidelines. Telephone discussions with the applicant were held on March 1 and 7, 1985, for clarification of several items.

The procedures submitted by the applicant have several plant-specific setpoints, operator action levels, and procedure references which are to be determined. The staff will confirm that the information required to complete each procedure is incorporated into the procedure before fuel loan through the routine prelicensing inspection program.

Justifications for several deviations included commitments by the applicant to change plant procedures, in most cases, based on improvements identified during the plant's procedure verification and validation effort. These changes were identified in deviations discussed on pages 7, 10, 16, 17, 19, 20, 27, 35, 39, and 52 of Attachment 1 to the January 15, 1985, letter. These changes must be completed before fuel load. In addition, the applicant committed to change or clarify the deviations on pages 18, 34, and 50 of Attachment 1 to the January 15, 1985, letter. The staff will confirm the acceptability of these revised deviations in an SER supplement.

The staff identified three errors associated with the deviations reviewed. First, although the justification on page 1 of Attachment 1 stated that generic Emergency Procedures Guidelines (EPG) Cautions 1-8 were addressed in training and not in the procedures, two cautions which the operators would be expected to have difficulty remembering (6 and 8) are, in fact, included in the procedures. The staff found this acceptable. Second, the staff found an inconsistency in the value used for the "maximum subcritical banked withdrawal position." The applicant stated that it had also found the inconsistency and that it had been corrected. The staff found this acceptable. Third, the staff identified an apparent typographical error in the justification for EOP-0002, step 3.4.4 (page 33 of the attachment) referencing 2 psig instead of 12 psig. On the basis of these changes, the staff found the material acceptable.

Finally, the RBS Emergency Operating Procedures direct the plant operators to vent the primary containment when containment pressure exceeds the "primary

containment pressure limit" as defined by a curve of primary containment water level versus suppression chamber pressure. The RBS limit proposed is based on an ultimate capacity of 56 psia which is in excess of the design pressure by a factor of about four. The NRC staff's Safety Evaluation Report on Revision 2 of the generic Emergency Procedure Guidelines (issued February 1983) has approved the use of twice design pressure as an interim limit provided containment integrity can be demonstrated. The staff is aware of a proposed revision to the generic EPGs which will result in a redefinition of the venting criteria. In this regard, it is the staff's intent to continue the review of the proposed venting criteria (both generically and for each plant) which place emphasis on the following areas:

(1) purge valve operability at the proposed venting pressure

(2) consideration of depressurization rate during venting to limit suppression pool flashing

(3) safety/relief valve actuation at high containment pressures

(4) structural analyses and tests

(5) limitation of offsite release rates by selective use of vent paths

The staff must complete its review of this item before operation above 5% power.

Figure 13.1 (Revision 1) River Bend Nuclear Group Management Structure

15 TRANSIENT AND ACCIDENT ANALYSIS

15.9 TMI Action Plan Requirements

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

Item II.K.1.5 - Assurance of Proper Engineered Safety Features Functioning

Confirmatory Item 62 required NRC Region IV to verify that procedures satisfied the requirements of IE Bulletin 79-08, Item 6. The staff of Region IV has determined by inspection that the applicant has issued appropriate procedures to meet the aforestated item. This will be documented in NRC Inspection Report 50-458/85-49.

This completes regional action on Confirmatory Item 62.

15.9.4 Item II.K.3 - Final Recommendations of Bulletins and Orders Task Force

Item II.K.3.31 - Plant-Specific Calculations To Show Compliance With 10 CFR 50.46

Plant-Specific LOCA Analysis

The staff's SER (Sections 6.3.3.3 and 15.9.4) reported the results of a lead plant loss-of-coolant accident (LOCA) analysis that was stated by the applicant to be representative of River Bend. The SER also noted that the applicant had committed to supply a plant-specific LOCA analysis for River Bend before fuel loading.

The applicant provided the LOCA analysis specific for River Bend in FSAR Amendment 15, dated November 1984. The plant-specific LOCA analysis included a spectrum of large and small pipe breaks and indicated that the most limiting break is a design-basis break in a recirculation suction pipe. As for the lead plant, an assumed failure of the low-pressure coolant injection (LPCI) diesel generator, coincident with the break, resulted in the worst single failure condition. The plant-specific results demonstrate compliance with the requirements of 10 CFR 50.46. (See revised Table 6.2.)

From its review, the staff concludes that the plant-specific LOCA analyses for River Bend are acceptable. This issue is closed.

18 HUMAN FACTORS ENGINEERING

The staff evaluation of the organization, process, and results of the River Bend detailed control room design review (DCRDR) contains the following elements, consistent with Section 18.1 and its Appendix A to Section 18.1 of the Standard Review Plan (NUREG-0800):

(1) an evaluation of the DCRDR Program Plan submitted by the applicant

(2) an onsite in-progress audit of the DCRDR conducted July 24-27, 1984

(3) an evaluation of the applicant's DCRDR Summary Report

(4) a preimplementation audit meeting with the applicant's DCRDR team leader and human factors contractor, January 23, 1985

(5) review of a letter dated January 23, 1985, providing supplemental information to clarify the applicant's DCRDR Summary Report

The staff was assisted in items 1-3 above by consultants from Lawrence Livermore National Laboratory (LLNL). Appended to this SER supplement is the Technical Evaluation Report (TER) prepared by LLNL (Appendix J). Except as noted, the staff concurs with the evaluation, conclusions, and recommendations contained in the LLNL report. The following summarizes the staff's evaluation findings regarding the required elements of the River Bend DCRDR.

18.1 Human Factors Engineering Team

The applicant has established and utilized a qualified multidisciplinary team to conduct the detailed control room design review (DCRDR). The concern raised (see Appendix J) that the applicant's Summary Report indicates a significant reduction in the participation of human factors specialists during the final implementation and verification of control room design changes has been acceptably addressed by the applicant in a letter dated January 23, 1985. The continued application of appropriate human factors expertise through the completion of DCRDR activities should be confirmed by the applicant in his scheduled supplement to the DCRDR Summary Report.

18.2/18.3 System and Task Analysis

The methodology described in the applicant's Summary Report and discussed in depth at the DCRDR in-progress audit provides an acceptable means to fulfill the function and task analysis requirements of the DCRDR. The information provided in the Summary Report, however, is insufficient to allow the staff or its consultants to determine if discrete operator tasks, decisions and actions associated with each task, and information and control requirements for successful task performance have been identified and analyzed to an acceptable level of detail. The staff met with the applicant's DCRDR team leader and human factors consultants on January 23, 1985, to determine if these processes have been adequately performed and documented. The staff audited the DCRDR task

analysis documentation for selected emergency scenarios. The sample audited revealed that the applicant has identified the discrete tasks, decisions, and actions operators need to undertake in order to carry out emergency actions. Review of the documented information and control capability requirements for task performance, however, indicates that the applicant applied a broader definition of "requirements" than the staff had anticipated. As a result, the information and control requirements include more than the minimum requirements for completing the task. Because of this, the subsequent comparison of information and control requirements with the controls and displays in the existing control room appears, as currently documented, to indicate more discrepancies than the applicant has reported. On the basis of the explanation of the verification of availability and suitability of displays and controls which was provided at the audit meeting, the staff believes that the process employed was adequate and identified human engineering discrepancies (HEDs) correctly. In order to confirm this, the applicant should provide written documentation for at least one emergency sequence which unequivocally demonstrates how it was determined that the inventoried displays and controls provided the necessary information and control capability. This information may be provided in the scheduled supplement to the DCRDR Summary Report.

18.4 The Main Control Room

18.4.1 Control Room Inventory

Although the control room inventory compiled by the applicant does not conform precisely to that recommended by the staff, the approach used is satisfactory. The documentation required to confirm the acceptability of the task analysis (see preceding paragraph) will also serve to confirm that the control room inventory function has been met.

18.4.2 Control Room Survey

With the exception of items which have not been completed because of the construction status of the plant, the control room survey conducted as part of the DCRDR meets the requirements of Supplement 1 to NUREG-0737. Control room survey items which must be completed before fuel load include: lighting; heating, ventilation, and air conditioning (HVAC); noise levels; communications; and the availability of procedures and adequate protective clothing. The applicant has committed to evaluate these items and report the results to NRC in a supplement to the DCRDR Summary Report before fuel load. This is acceptable to the staff if the supplement also provides resolutions and an acceptable implementation schedule for any HEDs identified and assessed as significant.

18.4.3 Assessment of HEDs

The method applied by the applicant to assess the significance of HEDs satisfies the requirements of Supplement 1 to NUREG-0737.

18.4.4 Selection of Design Improvements

The applicant's approach to selecting design improvements which will correct significant HEDs is potentially acceptable for meeting the DCRDR requirements. However, on the basis of a review of the priority 1 and 2 discrepancy records

in Section 7 of the applicant's Summary Report, the appropriateness of the proposed resolution of numerous HEDs is uncertain and/or unacceptable to the staff. The HEDs for which further information and/or additional action is needed are specified in Appendices A and B of the technical evaluation report (TER) that appears in this supplement as Appendix J. These HEDs fall into several categories which will require the applicant to take different degrees of action in order to resolve the HEDs to NRC's satisfaction. Many HEDs in question will require only a firmer commitment to implement a specific resolution consistent with good human engineering practices. In its letter of January 23, 1985, the applicant provided a generic commitment to develop and apply appropriate conventions and to implement certain displays associated with the safety parameter display system (SPDS) before fuel load. This commitment should be made specific to the HEDs identified in the appendices to the TER. Other HEDs with which the staff has concern will require either additional, more detailed justification for the proposed resolution or modification to the proposed resolution. For those HEDs which the TER recommends implementing before fuel load rather than before exceeding 5% power, the applicant should either modify its implementation schedule accordingly or provide justification for delaying implementation. Of particular concern to the staff is the possibility that, as now scheduled, some modifications may interfere with initial reactor startup operations.

The applicant should include the resolutions to the referenced HEDs in its scheduled supplement to the DCRDR Summary Report.

18.4.5 Verification of Design Improvements

The staff generally agrees with the recommendations in the appended TER (Appendix J) regarding verification that design improvements provide the necessary corrections and do not introduce new HEDs. The staff only requires, however, that the applicant confirm that modifications to the control room have been or, in the case of modifications not yet implemented, will be verified to ensure that the desired correction has been obtained without introducing new HEDs.

18.4.6 Coordination of DCRDR With Other Activities

Although the appended TER (Appendix J) notes some deficiencies in the documentation of the coordination and integration of the DCRDR with other Supplement 1 to NUREG-0737 activities, the staff does not require additional documentation at this time. The staff may, however, require additional information about the integration of the River Bend SPDS into the control room during its review and audit of the SPDS.

Conclusions

The staff concludes that, with the exception of the issues identified below, the applicant meets the relevant requirements of Supplement 1 to NUREG-0737 for conducting a detailed control room design review. The applicant should provide for staff review information that will:

(1) Confirm the continued participation of human factors specialists in remaining DCRDR activities (Confirmatory Item 66).

(2) Document the adequacy of the DCRDR task analysis (Confirmatory Item 67).

(3) Confirm that the remaining control room survey items have been completed and provide acceptable resolutions and implementation schedules for any significant HEDs identified (Outstanding Issue 20b).

(4) Respond to the specific concerns regarding resolution of the HEDs identified in Appendices A and B to the technical evaluation report appended to this supplement (Appendix J) (Outstanding Issue 20c).

(5) Confirm that all control room modifications resulting from the DCRDR have been verified to ensure they provide the expected correction and do not introduce new HEDs (Confirmatory Item 68).

This information should be included in the supplement to the applicant's Summary Report to be provided before fuel load.

SUPPLEMENTAL SAFETY EVALUATION REPORT

RIVER BEND STATION

AUXILIARY SYSTEMS BRANCH

3.6.1 Protection Against Dynamic Effects Associated With The Postulated Rupture of Piping

In our SER, we stated that the applicant's analysis indicated that the main steam isolation valve (MSIV) closure would be expected to terminate the blowdown from a main steam line break within 5.5 seconds. Furthermore, the applicant was to provide detailed information from this analysis for our review. The applicant has changed the time until MSIV closure to 10.5 seconds. In a submittal dated May 14, 1985, the applicant justified the 10.5 second time as follows. A high flow instrument sensing time of 0.1 seconds and an instrument delay time of 0.3 seconds were assumed. The MSIV's are designed to close between 3.0 and 5.0 seconds. This leaves an overall conservatism of 5.1 seconds in their analysis. This is acceptable.

We also stated in our SER that the applicant had not provided sufficient information for us to perform an independent calculation to verify the applicant's analysis of the environmental conditions in a compartment after a high energy line break (HELB). The applicant has subsequently provided the additional information. We have reviewed the information and have performed an independent analysis of the subcompartment environmental conditions following a HELB. Our analysis indicates that the applicant has appropriately determined the subcompartment conditions by predicting more conservative conditions than was predicted by our independent analysis. This is acceptable.

In our SER we stated that the applicant had not completed their analysis of the rupture of high-energy piping systems and their analysis of compartment flooding due to moderate energy line cracks. The applicant has now completed their analyses and has provided the results in an amendment to the FSAR. The applicant further has provided the results of an analysis of the effects of the jet impingement from longitudinal cracks in the main steam or feedwater piping in the break exclusion area of the main steam tunnel. The potential jet impingement targets in this area were identified and assumed to fail to function due to the jet forces. The applicant's analysis indicates that the failed components would not prevent a safe shutdown. A structural evaluation was performed which verified that the structure will retain its integrity considering the effects of jet impingement, pressure and flooding. In a submittal dated May 14,1985, the applicant stated that the main feedwater piping in the steam tunnel had been analyzed and is supported in accordance with seismic Category I criteria. Therefore the failure of the non-seismic

Category I main feedwater piping in the steam tunnel will not adversely effect the safety-related main steam lines or other safety-related components. We have reviewed these analyses and conclude that the applicant has appropriately used the guidance in Standard Review Plan Section 3.6.1 and Branch Technical Position ASB 3-1 in evaluating the effects of high- and moderate-energy pipe failures and the guidance of Regulatory Guide 1.29, Position C.2, as related to protecting safety-related components from failure of non-safety related components. The applicant has adequately designed and protected areas and systems required for safe shutdown.

Based on the above, we conclude that the design of the facility meets the requirements of General Design Criterion 4, with regard to protection against environmental conditions and missiles and the guidelines of Regulatory Guide 1.29, Position C.2, concerning protection of safety-related components from the failure of non safety-related components, and is, therefore, acceptable. The design of the facility meets the acceptance criteria of SRP 3.6.1.

4.6 Functional Design of Reactivity Control Systems

In FSAR Amendment 20, the applicant provided revised pages in order for the FSAR to conform to the proposed plant Technical Specifications. One of the "revised FSAR" pages was Figure 9.3-14 which graphically defines the upper and lower bounds of the allowable sodium pentaborate concentrations and volume. The previous revision of Figure 9.3-14 was the standard General Electric figure with the concentrations ranging from approximately 12% to 13.8% and the volume ranging from approximately 4600 gallons to 5160 gallons with a safety margin volume of approximately 250 gallons. The new figure has a concentration range of approximately 9.3% to 13.8% and the volume ranges from 3542 gallons to 5150 gallons with no safety margin. No explanation was provided for the change. Based on our independent calculations, the lower concentration level of 9.3% is non-conservative with respect to previously approved concentration and volume levels. The applicant subsequently provided a revised figure in a submittal dated July 8, 1985 which shows the minimum concentration as 10.5%. This concentration level was compared to other previously approved analyses and found to provide similar boration rates. Therefore we conclude that the revised figure provided by the July 8th submittal is acceptable. The applicant has also committed to revise the figure in the Technical Specifications.

Based on the above, we conclude that the design of the reactivity control system meets the requirements of General Design Criteria 26, "Reactivity Control System Redundancy and Capability", and 27, "Combined Reactivity Control System Capability", and is, therefore, acceptable. The functional design of the reactivity control system meets the applicable criteria of SRP 4.6.

5.2.5 Reactor Coolant Pressure Boundary Leakage Detection

The Standard Review Plan Section 5.2.5 and Regulatory Guide 1.45 discuss the need to monitor leakage from the reactor coolant pressure boundary to other systems and is identified as intersystem leakage. This intersystem leakage, as identified in the Regulatory Guide, is both 1) leakage across components, such as heat exchangers, to other water systems, such as the reactor plant component cooling water system, and 2) across passive components, such as across closed isolation valves. The applicant has provided means to detect the first type of intersystem leakage, as we have previously discussed in our SER. In Amendment 21, the applicant has identified a means to detect the second type of intersystem leakage, which is also referred to as the high/low pressure interface leakage, by monitoring the pressure between the two isolation valves. Detection of high pressure between the two valves is an indication of primary coolant leakage and is alarmed in the control room. Thus we conclude that the method for detecting leakage across the high/low pressure interfaces meets the requirements of General Design Criterion 2, "Design Basis for Protection Against Natural Phenomena".

Based on the above, we conclude that the reactor coolant pressure boundary leakage detection system meets the requirements of General Design Criterion 2, with regard to protection against natural phenomena, and the guidelines of Regulatory Guide 1.29, Positions C.1 and C.2, concerning the system seismic classification, and is, therefore, acceptable. The reactor coolant pressure boundary leakage detection system meets the acceptance criteria of SRP 5.2.5.

9.2.5 Ultimate Heat Sink

In Amendment 16, the applicant identified a reduction of the diesel generator loading due to delayed starting of the ultimate heat sink (UHS) fans based on the ultimate water temperature rise in the ultimate heat sink basin. In order to assure that the basin water temperature would not rise above the design ambient temperature, the applicant, in their submittal dated May 20, 1985 (RBG-21052), committed to have installed prior to start up following the first refueling outage an ultimate heat sink basin temperature monitoring system. This system is to determine the average basin water temperature with a continous readout and alarm in the control room. The applicant has stated that because of the time needed to design, procure, install, and test the temperature monitoring systmm, installation of the monitoring system cannot be completed prior to power operation. By submittal dated July 18, 1985, the applicant committed to provide the design of the temperature monitoring system for our review and approval prior to its installation.

As an interim measure, the applicant has committed to manually taking basin water temperature readings daily with an increasing frequency based upon the actual water temperature. At a water temperature between 75 and 80 degrees F, the water temperature will be measured every four hours; and every two hours when the water temperature exceeds 80 degrees F. The ultimate heat sink and the standby service water system are declared inoperable when the basin water temperature reaches 82 degrees F. The basis for the deferral of the installation of the UHS basin water temperature monitoring system is our judgement that the interim procedures provide a level of safety comparable to the design of the new system for the short period of operation of one cycle.

Based on our review, we conclude that the ultimate heat sink design is acceptable pending the following conditions:

1. The applicant will submit the design of an acceptable temperature monitoring system for our review prior to the first refueling.

2. The applicant will have installed the temperature monitoring system and proposed modification to the Technical Specifications (both to delete the interim Technical Specifications and to incorporate the new design into the Technical Specifications) prior to startup following the first refueling outage.

In Amendment 20 and the July 18th submittal, the applicant provided the design of a new system to be installed within the UHS. The new system is a hypochlorite feeding and recirculation system. In a submittal dated July 18, 1985, the applicant stated that the hypochlorite feeding system is designed to control organic growth in the UHS. A concentration level of 3.0 to 5.0 ppm of free chlorine will be injected into the UHS basin and verified by sample analysis when 1) makeup water is added to the UHS; 2) the standby service water system is operated or tested; or 3) microbological growth is detected. This system consists of a hypochlorite feed tank, a positive displacement feed pump, a recirculation pump, and piping. The piping in the UHS is plastic except for the piping near the standby service water pumps. The hypochlorite system is designed to inject 25 gpm of sodium hypochlorite into the UHS for about 2 hours per day for 3 days per week to maintain the minimum chlorine level in the UHS. This system is not safety-related and failure of this system will not adversely affect the UHS or the standby service water system. Thus the requirements of General Design Criterion 2, "Design Basis for Protection Against Natural Phenomena", and guidelines of Regulatory Guide 1.29, Position C.2, are satisfied.

In Amendment 16 to the FSAR, the applicant modified the operation of the ultimate heat sink fans from automatic initiation with the starting of the diesel generators to manual initiation from the control room two hours into design basis accidents inorder reduce the diesel generator loadings. The applicant indicated in a submittal dated May 14, 1985, that manual initiation of the fans two hours

after the commencement of the design basis accident would not have any adverse consequences. The applicant indicated that the water temperature would rise approximately 2.2 degrees F per hour without the fans operating.

Based on the applicant's commitment to install an UHS basin water temperature monitoring system, the license condition, the installation of a seismic Category I, Class 1E basin water temperature monitoring system by the first refueling outage, and the interim measures, we conclude that manually initiation of the ultimate heat sink fans prior to reaching a basin water temperature of 82 degrees F is acceptable. Therefore the requirements of General Design Criterion 44, "Cooling Water", as related to the ability of the UHS to accepted the heat rejected by the plant, are satisfied.

Based on the above, we conclude that the UHS meets General Design Criteria 2 and 44, as related to protection against natural phenomena and the capability to reject the heat loads from safety-related components under emergency conditions including a single active failure, and is, therefore, acceptable. The UHS meets the acceptance criteria of SRP 9.2.5.

9.2.7 Standby Service Water System

In our SER, we stated that each loop of the standby service water system (SSWS) is powered from its associated diesel. The A and C SSWS pumps in the A loop are powered from the Division I diesel generator and the B and D SSWS pumps in the B loop are powered from the Division II diesel generator. In Amendment 16 to the FSAR, the applicant removed the C SSWS pump and the associated instrumentation and controls from the Division I diesel generator and proposed powering it only from the Division III (HPCS) diesel generator. Thus the C SSWS pump only operates when the Division III diesel generator operates.

The applicant provided a failure modes and effects analysis which demonstrates the ability of the SSWS to withstand any single failure and provide sufficient cooling water to assure a safe shutdown for all design basis events. We have reviewed the revised failure modes and effects analysis and concluded that there is no single failure which will result in insufficient SSWS cooling water.

In our SER we also stated that each of the SSWS pumps were 50% capacity and therefore only two pumps were needed for safe shutdown. While these pumps are rated as 50%, for design basis accidents, where the single failure is the Division III (HPCS) diesel generator, three pumps are needed for a safe shutdown. This is acceptable because with the single failure of the HPCS diesel generator and the resulting loss of the C SSWS pump, there will still be three SSWS pumps available.

Each SSWS loop returns the cooling water to the ultimate heat sink, which is a forced draft cooling tower. The Division II powered pumps return the water to an area of the cooling tower which is served by the Division II fans. The Divisions I and III powered pumps return the water to an area of the cooling tower which is served by the Division I powered fans. There is a cross tie between the redundant loops such that the A and C SSWS pumps could supply water to the components and systems which would normally be serviced by the B and D SSWS pumps. Based upon the independence of the operability of the cooling tower fans and the SSWS pumps, the possibility exists that the SSWS pumps in one loop and the cooling tower fans associated with the other loop may be inoperable concurrently. Thus, the appropriate number of SSWS pumps and fans may be operable but the "system" may not be able to adequately remove sufficient heat to safely shutdown the plant. The applicant has provided an acceptable Technical Specification which requires the two operable SSWS pumps to be aligned to the loop with the two operable cooling tower fans whenever either of the following conditions exist: 1) two SSWS pumps in the same loop are inoperable and at least one fan in the other loop is inoperable or 2) two cooling tower fans in the same loop are inoperable and at least one SSWS pump in the other loop in inoperable.

Based on the acceptable Technical Specification concerning the alignment of the operable SSWS pumps and the cooling tower fans, we conclude that the standby service water system meets General Design Criterion 44, "Cooling Water", as related to the capability of transferring heat loads from safety-related components to the ultimate heat sink under emergency conditions including a single active failure, and is, therefore, acceptable.

9.3.3 Equipment and Floor Drainage Systems

In our SER we stated that the floor drains were pumped from the ECCS compartments and safety-related areas to the radwaste system. By Amendment 20, the applicant has provided a new operating mode for two of the floor drainage systems in the auxiliary building which routes the water to either the suppression pool or to the radwaste system. The areas affected by this change are the reactor plant closed cooling water system; the steam tunnel area which includes the leakoffs associated with the RCIC system; some of the components serviced by the normal/standby service water system; the standby gas treatment system; the floor drains in the auxiliary building crescent area at elevation 70; some unit coolers; MSIV positive leakage control system; the HVAC systems for the reactor, auxiliary, turbine, and containment buildings; some compressor/dryer systems; some fire protection sprinkler drains; and miscellaneous area floor drains for such areas as elevators, instrument racks, hatchs, and electrical terminal boxes. The auxiliary building crescent area contains ECCS piping which could leak. Leakage from this piping could reduce the inventory in the suppression pool.

With this new operating mode, the two affected systems have been identified as the suppression pool pumpback system (SPPS). Since this is only a new operating mode of a previously approved system, we conclude that the SPPS meets the requirements of General Design Criterion 4, "Environmental and Missile Design Bases". The SPPS consists of two sumps with two pumps per sump. The pumps, isolation valves, and level detection instrumentation are seismic Category I and Class 1E powered. The piping from the isolation valves to the suppression pool interface at the high pressure core spray return line is seismic Category I, Safety Class 2. The rest of the piping is non-seismic Category I but is seismically supported. Therefore, we conclude that the SPPS meets the requirements of General Design Criterion 2, "Design Basis for Protection Against Natural Phenomena", and the guidelines of Regulatory Guide 1.29, "Seismic Design Classification." The operation of the SPPS is either manually from the control room or automatically from the level sensors. By installing this new operating mode, the applicant has not deleted the option of pumping the water to the radwaste system. The use of this system to pump the water to the suppression pool provides additional time for the operator to identify the source of leakage while maintaining suppression pool water level and preventing excessive buildup of water in the auxiliary building.

Selection of the option to pump back to the suppression pool is by means of opening a motor operated valve. Opening this valve automatically closes the air operated valves to the radwaste system. The air operated valves are fail closed valves which prevent inadvertant pumping to the radwaste system during a LOCA.

Based on the above, we conclude that the SPPS meets the requirements of General Design Criteria 2 and 4, with regard to protection against natural phenomena, environmental conditions, and missiles, and the guidelines of Regulatory Guide 1.29, Positions C.1 and C.2, concerning the system seismic classification, and is, therefore, acceptable. The SPPS meets the acceptance criteria of SRP 9.3.3.

9.3.5 Standby Liquid Control System

In our SER we concluded that the standby liquid control system was acceptable based, in part, on the similarity between the FSAR Figure 9.3-14 and the General Electric standard figure which identifies the acceptable bounds of tank volume and sodium pentaborate concentration levels. (This issue is also discussed in Section 4.6 of this SSER.) By Amendment 20 to the FSAR, the applicant provided a revised figure 9.3-14 which identifies a lower concentration, smaller tank volume, and no safety margin in the total tank storage capacity. Based on the our independent calculations, the lower concentration level of 9.3% is non-conservative with respect to previously approved concentration and volume levels. The applicant provided a revised figure by submittal dated July 8, 1985 which shows the minimum concentration as 10.5%. This concentration level was compared to

other previously approved analyses and found to provide similar boration rates. Therefore, we conclude that the revised figure provided by the July 8th submittal is acceptable. The applicant has also committed to revise the figure in the Technical Specifications.

Based on the above, we conclude that the design of the standby liquid control system meets the requirements of General Design Criteria 26, "Reactivity Control System Redundancy and Capability", and 27, "Combined Reactivity Control System Capability", and is, therefore, acceptable. The functional design of the standby liquid control system meets the applicable criteria of SRP 9.3.5.

9.4.1 Control Building Ventilation System (Control Room Area Ventilation System)

In our SER we stated that the control building ventilation system includes the control building chilled water system. The chilled water system consists of two redundant, closed-loop chilled water trains with each train capable of meeting the total chilled water needs of the control building. Each train contains two 50% capacity electric-motor-driven centrifugal liquid chillers with both trains (all four chillers) powered from the essential service busses so that emergency power is available from the diesel generators if offsite power is lost. By Amendment 20, the applicant proposed to automatically initiate one of the two water chillers on each train and to automatically start the second chiller upon failure of the lead chiller in the respective ventilation train in order to reduce the electrical loading on the Division I and Division II diesel generators.

The applicant has provided the results of an analysis of the control building heat loads assuming the loss of a Division I or Division II diesel generator as the single active failure, for all design basis events. This analysis indicates that the heat load will be significantly reduced due to the reduction in equipment and instrumentation being powered due to the loss of a Division I or Division II diesel generator. (The loss of the Division III diesel generator will have no effect in that it powers no safety related equipment in the control building.) With both Division I and II diesel generators operating, one 50% capacity water chiller would be automatically initiated in each train, for a total of 100% capacity, and thereby meet all of the chilled water requirements for the control building. With the single failure of one of the automatically initiated water chillers, the second chiller in the train with the failed chiller would automatically start. If the single failure is a ventilation train, there is sufficient time for the operator to manually initiate the second chiller in the operating ventilation train.

Based on the above, we conclude that having one automatically initiated water chiller in each of the two redundant chilled water trains

and having the second chiller in each train automatically initiated upon failure of the lead chiller in the respective ventilation train is acceptable. This does not change our conclusions as previously stated in our SER.

9.4.6 <u>Miscellaneous Building Heating, Ventilation, and Air Conditioning Systems</u>

In our SER we stated that there were six miscellaneous building HVAC systems. By Amendment 20, the applicant added eight more miscellaneous building HVAC systems, as follows.

(7) motor generator building (heating and ventilation system)

(8) demineralized water pump house (heating and ventilation system)

(9) circulating water pump house and switchgear room (heating and ventilation system)

(10) cooling tower switchgear house (heating and ventilation system)

(11) clarifier area switchgear house (heating and ventilation system)

(12) hypochlorite area switchgear house (heating and ventilation system)

(13) blowdown pit (heating and ventilation system)

(14) auxiliary control building (heating, ventilation, and air conditioning system)

These additional miscellaneous building heating, ventilating, and air conditioning systems are located in non safety-related buildings and are designed to provide a suitable environment for personnel and equipment operation. None of these systems has any safety-related function, nor does failure of any system compromise any safety-related system or components. Failure of any system will not prevent safe shutdown of the reactor. Therefore, no system is designed to seismic Category I standards or to Quality Group A, B, or C standards. Therefore the guidelines of Regulatory Guide 1.29, "Seismic Design Classification", Position C.2, are satisfied and thus the requirements of General Design Criterion 2, "Design Basis for Protection Against Natural Phenomena", are satisfied. These systems are not designed to control release of radioactive material; therefore, General Design Criterion 60, "Control Releases of Radioactive Materials to the Environment," is not applicable.

Based on the above, we conclude that these additional miscellaneous building heating, ventilating, and air conditioning systems meet the requirements of General Design Criterion 2 and the guidelines of Regulatory Guide 1.29, Position C.2, and are, therefore, accep-

table. These additional systems meet the acceptance criteria of SRP 9.4.3.

STRUCTURAL AND GEOTECHNICAL ENGINEERING BRANCH
EVALUATION REPORT
RIVER BEND IN-PLANT SRV TESTINGS

References: 1. Letter from J. E. Booker to H. R. Denton dated October 8, 1985 and its attachment

2. Letter from J. E. Booker to H. R. Denton

In accordance with criterion 5 of NUREG-0763 River Bend Steel containment is required to undergo in-plant SRV testing, since no steel containment has been subjected to such testing. The applicant, Gulf States Utilities Company, requested relief from the testing requirement on the ground of following reasons:

1. Even though River Bend has a free-standing steel containment, the annulus, that is, the space between the shield building and the steel containment which forms the boundary of the suppression pool, has been filled with concrete. As a result this portion of the containment which forms the boundary of the suppression pool is as rigid as the reinforced concrete containment of Kuosheng which has undergone in-plant SRV testing. Therefore, the testing results of Kuosheng can be applied to River Bend.

2. Perry Nuclear Power Plant also has a free standing steel containment, and lower portion of the annulus same as River Bend is filled with concrete. A study was made by Cleveland Electric Illuminating Co. for Perry using a pressure time history from the Kuosheng tests as the forcing function input to the Perry structural models to obtain the response of the containment and internal structures. The resulting response spectra at selected node points are enveloped by

the Perry SRV design response spectra except in the high frequency region where similar excedance as noted in the Kuosheng study appears. However, detailed investigation indicated that there is adequate design margin for piping and equipment at Perry. On the basis of the review of the applicant's findings the staff concluded that Perry need not undergo any in-plant SRV tests. Since River Bend has a containment very similar to that of Perry, there is no need for River Bend to have any in-plant tests.

NRC staff reviewed the information provided by the applicant and found that the shear wave velocity of River Bend is much lower than that of Perry, which may have different effects on the response of the containment structure, components and systems located therein. In response to this staff concern, the applicant reasoned that the Kuosheng observed pressure trace does not excite lower modes of vibration of the Perry analytical model, nor of the actual Kuosheng structure. The response spectra used in the River Bend design based on the GE SRV forcing functions provide significant responses in the lower frequencies. This indicates that the River Bend design used SRV load which have more energy in the lower frequencies and is therefore more conservative in this region than the Kuosheng traces indicated. On the basis of review and evaluation of the information as provided by the applicant the staff concludes that there is no need to perform in-plant SRV testing at River Bend.

ATTACHMENT 1

GULF STATES UTILITIES COMPANY
RIVER BEND STATION
DOCKET NUMBER 50-458

SAFETY EVALUATION REPORT SUPPLEMENT

MATERIALS ENGINEERING BRANCH
INSERVICE INSPECTION SECTION

5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

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

5.2.4.3 Evaluation of Compliance with 10 CFR 50.55a(g) for River Bend Station

This evaluation supplements conclusions in this section of NUREG-0989, which addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). The design of the ASME Code Class 1 and 2 components of the reactor coolant pressure boundary incorporates provisions for access for inservice examinations, as required by Paragraph IWA-1500 of Section XI of the ASME Code. Paragraph 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 the construction permit date of March 25, 1977, this section of the 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 applied to the construction of the particular components. The components (including supports) may meet requirements set forth in subsequent editions and addenda of this Code which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein. The Applicant has prepared the PSI Program based on compliance with the requirements of the 1977 Edition of the Code including Addenda through Summer 1978 except for the reactor pressure vessel (RPV) or where specific written relief is requested.

The staff has reviewed the results of the public meeting with the Applicant on May 1, 1984 to discuss the PSI program, the FSAR through Amendment 20 (June 1985), the Applicant's May 15, 1985 response to the staff's request for additional information, the PSI Program through Revision 3 submitted on May 15, 1985, and other letters dated June 10, 1985 and June 24, 1985.

The RPV examination procedures, calibration blocks, and examinations comply with the requirements of the 1974 Edition of the Code including Addenda through Summer 1975 for the vessel shell welds, and the 1977 Edition and Addenda through Summer 1978 for safe end and safe end extension piping welds. The preservice examination of the reactor pressure vessel was performed in 1977 by a combination of manual and automated ultrasonic inspection equipment after completion of the hydrostatic test at the Chicago Bridge and Iron nuclear facilities at Memphis, Tennessee. Automated examinations were performed on shell seal welds in or below the core region and on the nozzle-to-vessel welds with pipe sizes 10 inch in diameter or larger. In addition, all areas of the N-1 through N-6 nozzle-vessel welds that were examined manually in 1977 were reexamined with automated equipment at River Bend Station. The safe ends for the same nozzles and the safe-end extension welds were also reexamined using the automated equipment. The Applicant states that all RPV examinations predate Regulatory Guide 1.150 which was issued in June 1981. The staff concludes that the preservice examinations of the RPV are acceptable because the preservice examinations were consistent with the applicable Code and the commercial practices at the time when examinations were performed.

As a result of the staff's request for additional information dated March 20, 1985, the PSI Program was completely revised and resubmitted on May 15, 1985. Therefore, the final program review with respect to the systems and components subject to examination was evaluated based on this submittal. In addition, Appendix C of this document contained requests for relief from ASME Code Section XI requirements that the Applicant has determined not practical for the ASME Class 1 systems and components. These relief requests were revised in letters dated June 10, 1985 and June 24, 1985, and were supported by a

technical justification. The staff evaluated the ASME Code required examinations that the Applicant determined to be impractical and pursuant to 10 CFR 50.55a(a)(3), relief from the impractical Code requirements has been allowed where the Applicant has demonstrated that either (i) the proposed alternatives would provide an acceptable level of quality and safety or (ii) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The detailed evaluation supporting this conclusion is provided in Appendix _____ to this report. Based on the granting of relief from these preservice examination requirements and review of the Applicant's submittals, the staff concludes that the preservice inspection program for reactor coolant pressure boundary is acceptable and in compliance with 10 CFR Part 50, Paragraph 50.55a(g)(3).

The initial inservice inspection program has not been submitted. This program will be evaluated after the applicable ASME Code edition and addenda can be determined based on Paragraph 50.55a(b) of 10 CFR Part 50, but before the first refueling outage when inservice inspection commences.

6.6 Inservice Inspection of Class 2 and 3 Components

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

6.6.3 Evaluation of Compliance with 10 CFR 50.55a(g) for River Bend Station

This evaluation supplements conclusions in this section of NUREG-0989, which addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). Based on the construction permit date of March 25, 1977, this section of the regulations requires that a PSI program for Class 2 and 3 components be developed and implemented using at least the edition and addenda of Section XI of the ASME Code applied to the construction of the particular components. The components (including supports) may meet the requirements set forth in subsequent editions of this Code and addenda which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations

and modifications listed therein. The Applicant has prepared the PSI Program based on compliance with the requirements of the 1977 Edition of the Code including Addenda through Summer 1978 except that the extent of examination for Class 2 welds in the residual heat removal (RHR) and emergency core cooling systems (ECCS) are determined by the requirements of the 1974 Edition of the Code with Addenda through Summer 1975, except where specific written relief is requested.

The staff has reviewed the results of the public meeting with the Applicant on May 1, 1984 to discuss the PSI Program, the FSAR through Amendment 20 (June 1985), the Applicant's May 15, 1985 response to the staff's request for additional information, the PSI Program through Revision 3 submitted on May 15, 1985, and other letters dated June 10, 1985 and June 24, 1985. As a result of the staff's request for additional information dated March 20, 1985, the PSI Program was revised and resubmitted in its entirety on May 15, 1985. Therefore, the final program review with respect to the systems and components subject to PSI examination was evaluated using this submittal. The most significant revisions which have been noted are:

- The exclusion of system pressure tests and visual examinations in accordance with IWC-1220 have been deleted. Although the terminology used in Paragraph IWC-1220 of Section XI, Summer 1978 Addenda is ambiguous, the intent of the ASME Code Committee as expressed in Examination Category C-H, "All Pressure Retaining Components" is clear. Paragraph IWC-1220 should not be used as a basis for excluding systems or portions of systems from the hydrostatic testing requirements of IWA-5000 and IWC-5000 of Section XI.

- The number of volumetric examinations was increased to at least 7.5% of the total number of welds in the RHR, ECCS and containment heat removal systems that are not exempt based on the ASME Section XI Code, 1974 Edition with Addenda through the Summer of 1975.

- Appendix D contains requests for relief from ASME Code Section XI requirements that the Applicant has determined not practical for Class 2 systems and components. These relief requests were revised in letters dated June 19, 1985 and June 24, 1985, and were supported by a technical justification.

The staff evaluated the ASME Code required examinations that the Applicant determined to be impractical and pursuant to 10 CFR 50.55a(a)(3), relief from the impractical Code requirements has been allowed where the Applicant has demonstrated that either (i) the proposed alternatives would provide an acceptable level of quality and safety or (ii) compliance with the requirements would results in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The detailed evaluation supporting this conclusion is provided in Appendix _____ to this report. Based on the granting of relief from these preservice examination requirements and review of the Applicant's submittals, the staff concludes that the preservice inspection program for River Bend Station is acceptable and in compliance with 10 CFR Part 50, Paragraph 50.55a(g)(3).

The initial inservice inspection program has not been submitted. This program will be evaluated after the applicable ASME Code edition and addenda can be determined based on Paragraph 50.55a(b) of 10 CFR Part 50, but before the first refueling outage when inservice inspection commences.

ATTACHMENT 2

APPENDIX ___

GULF STATES UTILITIES COMPANY
RIVER BEND STATION
DOCKET NUMBER 50-458

SAFETY EVALUATION REPORT SUPPLEMENT
PRESERVICE INSPECTION RELIEF REQUEST EVALUATION

MATERIALS ENGINEERING BRANCH
INSERVICE INSPECTION SECTION

I. INTRODUCTION

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

For nuclear power facilities whose construction permit was issued on or after July 1, 1974, 10 CFR 50.55a(g)(3) specifies that components shall meet the preservice examination requirements set forth in editions and addenda of Section XI of the ASME Boiler and Pressure Vessel Code applied to the construction of the particular component. The provisions of 10 CFR 50.55a(g)(3) also state that components (including supports) may meet the requirements set forth in subsequent editions and addenda of this Code which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein.

In the River Bend Station PSI Program, Revision 3, submitted on May 15, 1985 and in letters dated June 10, 1985 and June 24, 1985, the Applicant requested relief from ASME Section XI Code requirements which the Applicant has determined to be not practical and provided a technical justification. Therefore, the staff evaluation consisted of comparing the Applicant's submittals to the requirements of the applicable Code edition and addenda and determining if relief from the Code requirements was justified.

II. TECHNICAL REVIEW CONSIDERATIONS

A. The construction permit for River Bend Station was issued on March 25, 1977 and components (including supports), which are classified as ASME Code Class 1 and 2, have been designed and provided with access to enable the performance of required preservice examinations set forth in the 1977 Edition of the ASME Boiler and Pressure Vessel Code, Section XI, including the Addenda through Summer 1978.

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

C. The intent of a preservice examination is to establish a reference or baseline prior to the initial operation of the facility. The results of subsequent inservice examination can then be compared with the original condition to determine whether changes have occurred. If the inservice inspection results show no change from the original condition, no action is required. In the case where baseline data are not available, all flaws must be treated as new flaws and evaluated accordingly. Section XI of the ASME Code contains acceptance standards which may be used as the basis for evaluating the acceptability of such flaws.

D. Other benefits of the preservice examination include providing redundant or alternative volumetric examination of the primary pressure boundary using a test method different from that employed during the component

fabrication. Successful performance of preservice examination also demonstrates that the welds so examined are capable of subsequent inservice examination using a similar test method.

In the case of River Bend Station, a large portion of the preservice examination required by the ASME Code was performed. Failure to perform a 100% preservice examination of the welds identified below will not significantly affect the assurance of the initial structural integrity.

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

In cases where parts of the required examination areas cannot be effectively examined because of a combination of component design or current examination technique limitations, the development of new or improved examination techniques will continue to be evaluated. As improvements in these areas are achieved, the staff will require that these new techniques be made a part of the inservice examination requirements for the components or welds which received a limited preservice examination. Several of the preservice inspection relief requests involve limitations to the examination of the required volume of a specific weld. The inservice inspection (ISI) program is based on the examination of a representative sample of welds to detect generic degradation. In the event that the welds identified

in the PSI relief requests are required to be examined again, the possibility of augmented inservice inspection will be evaluated during review of the Applicant's initial 10-year ISI program. An augmented program may include increasing the extent and/or frequency of examination of accessible welds.

III. EVALUATION OF RELIEF REQUESTS

The Applicant requested relief from specific preservice inspection requirements in Revision 3 of the River Bend Station PSI Program submitted May 15, 1985, and submitted revisions to these relief requests in letters dated June 10, 1985 and June 24, 1985. Based on the information submitted by the Applicant and the staff's review of the design, geometry, and materials of construction of the components, certain preservice requirements of the ASME Boiler and Pressure Vessel Code, Section XI have been determined to be impractical to perform. The Applicant has demonstrated that either (i) the proposed alternatives would provide an acceptable level of quality and safety or (ii) compliance with the specified requirements of this section would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(3), conclusions that these preservice requirements are impractical are justified as follows. Unless otherwise stated, references to the Code refer to the ASME Code, Section XI, 1977 Edition, including Addenda through Summer 1978.

A. Relief Request R0001, Examination Category B-J, Pressure Retaining Piping Welds (21 Welds)

Code Requirement: ASME Class 1, pressure retaining piping welds are required to receive a 100% surface and volumetric examination for PSI in accordance with IWB-2500-1, Examination Category B-J, Item B9.10.

Code Relief Request: Relief is requested from performing the Code required volumetric examination on the pressure-retaining welds listed below:

System & Weld Number	Type of Weld
ICS-006-057-1	
057BFW004	Pipe to flange
MSS-024-600-1	
600A2SW05E	Sweep-o-let to flange
600A2SW05D	Sweep-o-let to flange
MSS-024-700-1	
700A2SW08M	Sweep-o-let to flange
700A2SW08L	Sweep-o-let to flange
700A1SW08K	Sweep-o-let to flange
700A2SW08J	Sweep-o-let to flange
700A2SW08H	Sweep-o-let to flange
MSS-024-800-1	
800A2SW07K	Sweep-o-let to flange
800A2SW07J	Sweep-o-let to flange
800A2SW07M	Sweep-o-let to flange
800A2SW07L	Sweep-o-let to flange
800A2SW07N	Sweep-o-let to flange
800A2SW07P	Sweep-o-let to flange
MSS-024-900-1	
900A2SW06F	Sweep-o-let to flange
900A2SW06G	Sweep-o-let to flange
900A2SW06H	Sweep-o-let to flange
1B13*D020	
1-ICS-014A-SW001	Tee to Flange
1-ICS-014A-SW002	Tee to Flange
1-ICS-014A-SW003	Tee to Flange
1-ICS-014A-SW004	Tee to Flange

Reason for Request: Due to the configuration (pipe to flange, sweep-o-let to flange, or tee to flange), there is not sufficient area to perform a meaningful ultrasonic examination. Sketches showing the typical configuration of each weld were provided in the PSI Program.

Staff Evaluation: The staff has reviewed the geometric configuration of the subject welds and determined that the required preservice volumetric inspection, using ultrasonic techniques, is not practical because of the design of the component. This relief request is acceptable for PSI based on the following considerations:

1. Other welds in the same piping runs received full Code examinations. The overall integrity of the pressure boundary thus was verified by sampling.

2. These welds have been subject to a system hydrostatic test and found acceptable in accordance with ASME Code Section III, Class 1 requirements.

3. These welds have been volumetrically examined by radiography, and found acceptable in accordance with ASME Code Section III, Class 1 requirements.

4. These welds have also been surface examined by magnetic particle, and found acceptable in accordance with ASME Code Section XI, Class 1 requirements.

The above examinations and tests are an acceptable alternative for PSI and provide reasonable assurance of the preservice structural integrity of the subject welds. The staff has determined that compliance with the specified requirements would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety because the components would have to be removed and redesigned to provide an inspectable weld surface for ultrasonic inspection.

B. Relief Request R0002, Examination Category B-J, Pressure Retaining Piping Welds (6 welds)

Code Requirement: ASME Class 1, pressure retaining piping welds are required to receive a 100% surface and volumetric examination for PSI in accordance with IWB-2500-1, Examination Category B-J, Item B9.10.

Code Relief Request: Relief is requested from performing 100% of the Code required volumetric examination on the pressure-retaining welds listed below:

Standby Liquid Control Welds	Approximate % Examined
1-SLS-042B-FW016	70%
1-SLS-042B-FW009	60%
1-SLS-037C-FW004	65%

Reactor Core Isolation Cooling System Welds	Approximate % Examined
1-ICS-001B-SW010	75%

Main Steam Piping Sweep-O-Let Welds	Approximate % Examined
1-MSS-600A2-SW05D	75%
1-MSS-900A2-SW06E	75%

Reason for Request: Due to the location and configuration of adjacent component supports or welded pads located on weld metal repair, the required volumetric examination cannot be performed on 100% of the required weld volume. Sketches showing typical restrictions from adjacent structures were provided in the PSI Program. The staff has reviewed the design configuration of the adjacent structures and determined that the preservice inspection, to the extent required by the Code, is impractical.

Staff Evaluation: This relief request is acceptable for PSI based on the following considerations:

1. Other similar welds in the same piping runs received full Code examinations. Thus, the overall integrity of the pressure boundary was verified by sampling.

2. These welds were volumetrically examined by radiography and found acceptable in accordance with ASME Code Section III, Class 1 requirements.

3. These welds were subject to a system hydrostatic test and found acceptable in accordance with ASME Code Section III requirements.

4. The above welds have received the Code required surface examination and the accessible portions of the above welds have received a preservice volumetric examination in accordance with ASME Code Section XI.

Therefore, the staff concludes that the limited Section XI volumetric examination, the required Section XI surface examination and the Section III fabrication examinations performed during construction are an acceptable alternative for PSI and provide reasonable assurance of the preservice structural integrity of the subject welds.

C. Relief Request R003, Examination Category C-G, Pressure Retaining Welds in Pumps

Code Requirement: ASME Class 2 pressure retaining welds on pumps are required to receive a surface examination for PSI in accordance with ASME Section XI, IWC-2500-1, Examination Category C-G, Item C6.10.

Code Relief Request: Relief is requested from performing a preservice surface examination on those portions of welds located within the concrete pump support encasement on the following pumps.

Pump	Pump No.
Low Pressure Core Spray	IE21 PC001
High Pressure Core Spray	IE22 PC001
RHS "B"	IE12 PC002-A

Reason for Request: These welds are located in the pump housing and are encased in concrete. Examination of required welds would require complete disassembly of the pumps. Examination of the accessible pump casing welds were performed. If a pump is disassembled for normal maintenance, examination of the welds will be considered at that time. Sketches showing the installed configuration of the pumps were provided in the PSI Program.

Staff Evaluation: The staff has determined that disassembly of the pumps would be necessary to perform the required examination in the installed configuration. This relief request is acceptable based on the following considerations:

1. These welds have been volumetrically examined by radiography, and found acceptable in accordance with the ASME Code Section III, Class 2 requirements.

2. These pumps were subject to a system hydrostatic test and found acceptable in accordance with ASME Section III, Class 2 requirements.

3. The failure of these welds, thus leading to failure of the pump, would have no adverse affect on plant safety because redundant ECCS systems are provided.

The staff concludes that requiring a surface examination of the welds encased in concrete would result in hardships or unusual difficulties without a significant increase in the level of quality and safety because the radiography performed during fabrication and the hydrostatic test are equivalent or superior to the required preservice inspection. In the event that these pumps are disassembled for inservice repair or maintenance, such that the subject welds are accessible, the staff will require that the preservice inspection be performed at that time.

D. Relief Request R004, Examination Category B-O, Peripheral Control Rod Drive Housing Welds, and Examination Category B-G-2, Bolting Located on CRD Housings and Incore Housings

Code Requirement:

1. Peripheral control rod drive housing welds are required to be surface examined (liquid penetrant) for PSI in accordance with ASME Section XI, IWB-2500-1, Examination Category B-O.

2. Pressure retaining bolting for the flange to flange joints, located on the CRD and incore housings, are required to receive a visual examination (VT-1) for PSI in accordance with ASME Section XI, IWB-2500-1, Examination Category B-G-2.

Code Relief Request: Relief is requested from performing the liquid penetrant examinations on the peripheral CRD housing welds and the visual (VT-1) examinations on the subject bolting.

Reason for Request: The weld area and bolting is not accessible for examination unless the control rod drive (CRD) support structure is removed. A total 360° surface examination cannot be accomplished due to interference from adjacent CRD housings. Examination of the weld from the inside of the CRD housing would require that the control rod drive mechanisms be removed, which could result in damage to the drive.

Staff Evaluation: This relief request is acceptable for preservice inspection based on the following considerations:

1. The peripheral CRD housing welds have been volumetrically and surface examined by radiographic and liquid penetrant methods, and have been hydrostatic tested in accordance with ASME Code Section III requirements.

2. All incore and CRD housing bolting has been examined in accordance with the requirements of ASME Code Section III.

3. The welds and bolting were subject to hydrostatic testing and found acceptable per the requirements of ASME Code Section III.

The staff concludes that requiring the removal of the installed CRD support structure to perform the required surface and visual examinations would result in hardships and unusual difficulties without a compensating increase in the level of quality and safety because the radiography performed during fabrication and the hydrostatic test are equivalent or superior to the

required perservice inspection. In the event that the CRD housings are disassembled for inservice repair or maintenance, such that the subject welds and bolting are accessible, the staff will require that the perservice inspection be performed at that time.

E. Relief Request R005, Examination Category B-K-1, Integral Welded Attachments for Class 1 Piping, Pumps, and Valves, and Examination Category C-C, Integral Welded Attachments for Class 2 Piping, Pumps, and Valves

(Relief Request R005 has been withdrawn by the Applicant).

F. Relief Request R006, Examination Category B-J, Pressure Retaining Dissimilar Metal Piping Welds

Code Requirement: ASME Class 1, pressure retaining dissimilar metal welds are required to receive a 100% surface and volumetric examination for PSI in accordance with ASME Section XI, IWB-2500-1, Examination Category B-J, Note (1)(c), Item B9.11.

Code Relief Request: Relief is requested from performing 100% of the Code required volumetric examination on the following welds:

Line Number	Weld Number
1-RCS-020-900-A	900A-FWB25
1-RCS-020-800-A	800A-FWA24
1-RHS-018-900-A	900A-FWB22

Reason for Request: Due to the configuration of these welds (fitting to pipe), a meaningful ultrasonic examination can only be performed from one side of the weld. Sketches showing the typical configuration of each weld were provided in the PSI Program.

Staff Evaluation: The staff has reviewed the design configurtion of the subject welds and determined that the preservice inspection to the extent required by the Code is impractical. This relief request is acceptable for preservice inspection based on the following considerations:

1. These welds have been volumetrically examined by radiography and found acceptable in accordance with ASME Code Section III, Class 1 requirements.

2. These welds were subject to a system hydrostatic pressure test and found acceptable in accordance with ASME Code Section III, Class 1 requirements.

3. These welds have been surface examined by liquid penetrant and found acceptable in accordance with ASME Code Section XI, Class 1 requirements.

The staff has therefore concluded the limited Section XI volumetric examination, the required Section XI surface examination, and the fabrication examinations performed during construction are acceptable alternatives for PSI and provide reasonable assurance of the preservice structural integrity of the subject welds.

G. Relief Request R007, Examination Category B-J, Pressure Retaining Piping Longitudinal Welds

Code Requirement: ASME Class 1, longitudinal welds on 4 inch and greater NPS piping are required to receive a 100% surface and volumetric examination for PSI in accordance with ASME Section XI, IWB-2500-1, Examination Category B-J, Item B9.12 and paragraph IWB-2200(a).

Code Relief Request: Relief is requested from performing 100% of the Code required examination on the following welds:

System & Line	Weld Number
1-MSS-024-600-1	600A2SW05BL1
	600A2SW05BL2
1-MSS-024-900-1	900A2SW06BL1
	900A2SW06BL2
1-MSS-024-700-1	700A2SW08BL1
	700A2SW08BL2
1-MSS-024-800-1	800A2SW07BL1
	800A2SW07BL2
1-RCS-010-80G-1	800C-FWA16L
1-RCS-010-80D-1	800C-FWA13L
1-RCS-010-80E-1	800C-FWA14L
1-RCS-010-90D-1	900C-FWB13L
1-RCS-020-900-1	900A-SW004BCL
1-RCS-020-900-1	900A-SW004BBL2
1-RCS-020-80A-1	800B-FWA06L
1-RCS-020-800-1	800A-SW002ABL
1-RCS-020-900-1	900A-SW002BBL
1-RCS-010-80F-1	800C-FWA15L
1-RCS-010-90E-1	900C-FWB14L
1-RCS-010-90C-1	900C-FWB12L
1-RCS-010-90F-1	900C-FWB15L
1-RCS-010-90G-1	900C-FWB16L
1-RCS-010-80C-1	800C-FWA12L
1-RCS-020-80A-1	800B-SW007ABL
1-RCS-020-800-1	800A-FWA04L

Reason for Request: The required area of examination cannot be examined due to the location of integral attachments, branch connections, and Code identification plates. The location of the specific obstruction for each weld was identified. The accessible portion of these longitudinal welds will be examined in accordance with Section XI requirements.

Staff Evaluation: This relief request is acceptable for preservice inspection based on the following considerations:

1. The accessible portions of the above listed welds received a preservice volumetric and surface examination in accordance with the ASME Code Section XI.

2. Adjacent weld lengths in the same piping runs received full Code examination. The overall integrity of the pressure boundary thus was verified by sampling.

3. These welds have been volumetrically examined by radiography and found acceptable in accordance with ASME Code Section III requirements.

4. The subject piping welds received a system hydrostatic test and were found acceptable in accordance with ASME Code Section III requirements.

The staff has determined that the Code preservice examination was essentially completed on the majority of welds. The staff concludes that the limited Section XI volumetric examinations, the required surface examinations, and the fabrication examinations performed during construction are acceptable alternatives for PSI and provide reasonable assurance of the preservice structural integrity of the subject welds.

H. Relief Request R0008, Examination Category B-J, Pressure Retaining Welds in Piping

Code Requirement: ASME Class 1, pressure retaining piping welds are required to receive a 100% surface and volumetric examination for PSI in accordance with IWB-2500-1, Examination Category B-J, Item B9.10.

Code Relief Request: Relief is requested from performing 100% of the Code required volumetric examination on the fitting side of the following pipe to fitting or component welds:

System & Line	Weld	Weld Configurations
1-RCS-010-80C-1	800C-FWA12	Pipe to sweep-o-let
80D-1	800C-FWA13	Pipe to sweep-o-let
80F-1	800C-FWA15	Pipe to sweep-o-let
80G-1	800C-FWA16	Pipe to sweep-o-let

System & Line	Weld	Weld Configurations
1-RCS-020-80A-1	800C-FWA11	Pipe to TEE
80A-1	800B-FWA10	Pipe to valve
90A-1	900CX-SW014CA	Reducer to TEE
90A-1	900C-FWB11	Pipe to TEE
1-RCS-010-90F-1	900C-FWB15	Pipe to sweep-o-let
90G-1	900C-FWB16	Pipe to sweep-o-let
90D-1	900C-FWB13	Pipe to sweep-o-let
90C-1	900C-FWB12	Pipe to sweep-o-let
1-RCS-020-900-1	900A-SW004BA	Pipe to Tee
900-1	900A-SW004BC	Pipe to Tee
900-1	900A-FWB03	Pipe to pump
800-1	800A-FWA05	Pipe to pump
800-1	800A-FWA03	Pipe to valve
900-1	900A-SW005BA	Pipe to elbow
900-1	900A-FWB04	Pipe to valve
800-1	800A-SW005AA	Pipe to elbow
800-1	800A-FWA04	Pipe to valve
1-RCS-010-90G-1	900C-FWB21	Pipe to Nozzle
90F-1	900C-FWB20	Pipe to Nozzle
90E-1	900C-FWB19	Pipe to Nozzle
90D-1	900C-FWB18	Pipe to Nozzle
90C-1	900C-FWB17	Pipe to Nozzle
80C-1	800C-FWA17	Pipe to Nozzle
80D-1	800C-FWA18	Pipe to Nozzle
80E-1	800C-FWA19	Pipe to Nozzle
80F-1	800C-FWA20	Pipe to Nozzle
80G-1	800C-FWA21	Pipe to Nozzle

Reason for Request: Due to the configuration of these welds, the ultrasonic examination can only be performed from one side of the weld using a 1-1/2 V technique. Sketches showing the typical configuration of each weld were provided in the PSI Program.

Staff Evaluation: The staff has reviewed the geometric configuration of the subject welds and determined that the required preservice volumetric inspection, using ultrasonic techniques, is not practical from the fitting side because of the design of the component. This relief request is acceptable for preservice inspection based on the following considerations:

1. These welds have been volumetrically examined by radiography, and found acceptable in accordance with ASME Code Section III, Class 1 requirements.

2. These welds have also received a liquid penetrant surface examination and were found acceptable in accordance with ASME Code Section XI, Class 1 requirements.

3. These welds were subject to a system hydrostatic test and found acceptable in accordance with ASME Code Section III requirements.

4. The staff will continue to evaluate the development of new or improved procedures and will require that these improved procedures be made part of the inservice examination requirements.

The staff has determined that the limited Section XI examinations from the pipe side of the weld, the required surface examinations and the fabrication examinations performed during construction are acceptable alternatives for PSI as they provide reasonable assurance of the preservice structural integrity of the subject welds.

I. <u>Relief Request R0009, Examination Categories B-L-2 and B-M-2, Pump Casings and Valve Bodies</u>

<u>Code Requirement</u>: Class 1 pump casing internals and valve body internal surfaces are required to receive a visual examination (VT-1) for PSI in accordance with ASME Code Section XI, IWB-2500-1, B-L-2 Item B12.20 and B-M-2 Item B12.40.

<u>Code Relief Request</u>: Relief is requested from performing the required examination for PSI.

<u>Reason for Request</u>: Visual examination of the internals of the pumps and valves at this time would require disassembly, which would impose an undue hardship on the plant and may increase the probability of pump failure.

Staff Evaluation: This relief request is acceptable for PSI based on the following:

The subject pump casings and valve bodies were volumetrically examined by radiography and hydrostatically tested in accordance with ASME Code Section III requirements. Disassembly of pumps and valves at this time, for the sole purpose of performing preservice visual examination, would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The staff has concluded that these construction code examinations and tests exceed the requirements for visual examination and therefore, are an acceptable alternative to the Section XI preservice visual examination.

J. Relief Request R0010, Examination Category B-J, Pressure Retaining Piping Weld (1 weld)

(Relief Request R0010 has been withdrawn by the Applicant).

K. Relief Request R0011, Examination Category C-B, Pressure Retaining Nozzle Welds in Vessels

Code Requirement: Table IWC-2500-1, Examination Category C-B, Item C2.20, requires surface and volumetric examination of the regions described in Figure IWC-2500-4 for nozzles in vessels over 1/2 in. nominal thickness. Figure IWC-2500-4 requires volumetric examination of the inner radii on nozzles over 12 inch nominal pipe size.

Code Relief Request: Relief is request from performing the Code required volumetric examination on the nozzle inner radii for the following RHR heat exchanger nozzles:

Component Description	Nozzle Number
1-RHS-1-E12*EB 001-A	N3
1-RHS-1-E12*EB 001-A	N4

Reason for Request: The nozzles contain inherent geometric constraints which limit the ability to perform meaningful ultrasonic examination of the nozzle inner radii. To perform an alternate surface examination, the tube bundle would have to be removed from the heat exchanger. However, a surface examination will be performed if the heat exchanger is disassembled. Sketches of the nozzle configuration are provided in the PSI Program.

Staff Evaluation: The staff review of the design configuration of the nozzle inner radius has concluded that the Code required volumetric examination is impractical and would require redesign of the nozzle. This relief request is acceptable for PSI based on the following considerations:

1. The subject weld area received radiographic examination and a hydrostatic test during fabrication in accordance with ASME Code Section III requirements.

2. An ultrasonic examination has been performed on the nozzle to vessel welds per ASME Code Section XI requirements.

3. The staff will continue to evaluate the development of new or improved procedures and will require that the procedures be made part of the ISI examination requirements.

4. If the heat exchanger is disassembled, the Applicant has committed to perform an alternative surface examination.

The staff concludes that compliance with the Code requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety and the Section III hydrostatic test provides a reasonable assurance of an acceptable level of structural integrity of the nozzle inner radii region.

IV. CONCLUSIONS

Based on the foregoing, pursuant to 10 CFR 50.55a(a)(3), the staff has determined that certain Section XI required preservice examinations are impractical. The Applicant has demonstrated that either (i) the proposed alternatives would provide an acceptable level of quality and safety or (ii) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

The staff technical evaluation has not identified any practical method by which the existing River Bend Station can meet all the specific preservice inspection requirements of Section XI of the ASME Code. Requiring compliance with all the exact Section XI required examinations would delay the startup of the plant in order to redesign a significant number of plant systems, obtain sufficient replacement components, install the new components, and repeat the preservice examination of these components. Examples of components that would require redesign to meet the specific preservice examination provisions are the core spray pumps and a significant number of the piping and component support systems. Even after the redesign efforts, complete compliance with the preservice examination requirements probably could not be achieved. However, the as-built structural integrity of the existing primary pressure boundary has already been established by the construction code fabrication examinations.

Based on the staff review and evaluation, it is concluded that the public interest is not served by imposing certain provisions of Section XI of the ASME Code that have been determined to be impractical. Pursuant to 10 CFR 50.55a(a)(3), relief is allowed from these requirements which are impractical to implement.

ATTACHMENT 3

TRIP REPORT
GULF STATES UTILITIES
RIVER BEND STATION
JUNE 13-14, 1985

B. W. Brown
Idaho National Engineering Laboratory
EG&G Idaho, Inc.

The trip was made to Gulf States Utilities' River Bend Station for the purpose of assuring that the final draft supplement to the Safety Evaluation Report (SSER) with relief request evaluations is consistent with the PSI examinations being performed at the plant site.

Upon arrival at River Bend Station, I was met by John Lawrence, Nuclear Licensing Engineer, and taken to meet with Jimmy Blakely, ISI Engineer, Roger Carlyle, ISI Supervisor, and Jim Wright, ISI Manager. Following brief discussions on the purpose of the visit and what we expected to accomplish, I called Dwight Chamberlain, the Region IV NRC I&E Inspector, to confirm my presence at River Bend. Mr. Chamberlain requested that I meet with him, to briefly discuss any findings, prior to departure on Thursday.

The following is a listing of my activities during the two-day visit:

The balance of Wednesday morning and part of the afternoon was spent with Mr. Carlyle and Mr. Blakely reviewing a new submittal containing revised relief requests and three new relief requests.

Following this review, Mr. Blakely conducted an extensive plant tour. It was hard to believe that this plant was anywhere near completion as there were thousands of construction workers still on site with scaffolding, ladders, grinders, welders, and temporary wiring everywhere. The overall cleanup that you would expect to see as completion nears did not appear to have begun. The physical size of the components, the quantity of concrete, and the thousands of piping and support welds used in this facility was awesome. During the tour it was possible to view areas containing components and welds for which relief from the ASME Boiler and Pressure Vessel Code Section XI requirements was being requested. Most of these requests for relief appeared justified, however, it seemed necessary to review some of the examination reports in order to draw a final conclusion.

The request to see the examination records for the four 24 in. NPS welded flued heads in the Main Steam line showed that the records did not exist. This problem was partially traced to the fact that there were typographical errors in the PSI Program Plan weld lists. It was determined that these welds had not received the Code Section XI PSI surface examination. The Applicant stated that if the Code Section III fabrication examination records could be verified, they would be used to fulfill the PSI requirement as allowed by Code Section XI paragraph IWB-2200. If these records could not be located, the Section XI surface examinations would be performed on the accessible portions of the flued head welds and relief would be requested. Review of drawings and examination records for other integrally welded supports listed in relief request R005 showed a significant number of welds were not integrally welded attachments, but were welds attached to the integrally welded attachments. Code Section III

fabrication examination records will be used to satisfy the PSI surface examination on many of the welds requiring examination as allowed by IWB-2200 and IWC-2200. The Applicant committed to revise R005 to reflect these findings after all the examination records are verified.

Review of the Code Section XI surface examination records for Reactor Coolant System (RCS) welds on the 10 and 20 in. NPS lines verified that the surface examinations were done using the liquid penetrant method and not the magnetic particle method as the Applicant reported in relief requests R007 and R008. It was also shown that the RCS welds listed in relief request R007 did not agree with the welds listed in the PSI Program Plan, Appendix C. Either the RCS welds in relief request R007 or the Appendix C, RCS weld list, requires revisions. The Applicant agreed to verify the RCS welds requiring relief and revise relief requests R007 and R008 to correct the above observations.

Minor editorial errors were noted in relief requests R006 and R0010 and a systematic error was identified in Appendix F of the PSI Program. Appendix F, pages 58, 59, and 60, shows the RHS heat exchanger circumferential and longitudinal shell welds classified as "Integral Attachments for Vessels," Examination Category C-C. These welds should be classified as "Pressure Retaining Welds in Vessels," Examination Category C-A.

As a result of the above observations the Applicant committed to submit revised and new relief requests for staff review by June 21, 1985. The PSI Program will be reviewed for systematic errors and these will be corrected in later revisions to the PSI Program.

River Bend Station uses a CAD system for plant design and to track the size and location of each piece of pipe, structural component, and equipment within the plant. I had the opportunity to meet with Mr. Bob Powers of Construction Systems Associates for a brief tour and demonstration of the CAD System. The system constructs a three-dimensional computerized color model of the reactor plant and associated systems and is the basis for identification of the components for future inservice inspections. Some of the features of this equipment are:

- Stores the dimensions and locations of all piping and structural components.

- Locates these components within ±0.1 in. within the area of the containment or auxiliary buildings.

- The system plots views of any plan or elevation within the plant with all hidden lines removed and cut sections properly designated.

- Lists the weld or component identification number along with the NDE examinations, dates, the actual performance and status of the examinations, any interference to examination, any scaffolding, etc. which may be required; will list the radiation levels (during operation and plant shutdown) at the component for ALARA concerns.

When all of the data is incorporated for River Bend Station this will be a powerful tool for future maintenance and inservice inspections. If further information is desired on this system, I have several brochures, technical

articles, and isometric drawings which Mr. Powers provided for our information.

Just prior to leaving the plant site on Thursday, I met briefly with Mr. Chamberlain, NRC Region IV, per his request to discuss some of the above findings.

Conclusion: Although the River Bend Station PSI Program seems to be plagued with computer input errors, typos, etc., Gulf States Utilities seems to be making every effort to meet or exceed the Regulation and Code requirements.

LR 2

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

July 23, 1985

Docket No. 50-458

MEMORANDUM FOR: Thomas M. Novak, Assistant Director for Licensing
Division of Licensing

FROM: Don H. Beckham, Acting Deputy Director
Division of Human Factors Safety

SUBJECT: SUPPLEMENTAL SAFETY EVALUATION REPORT INPUT
RIVER BEND STATION, UNIT 1
INITIAL PLANT TEST PROGRAM

The Initial Plant Test Program of the River Bend Station was reviewed and approved through amendment 10 of the FSAR and documented in the Safety Evaluation Report. Recently, we have completed our review of FSAR amendments through amendment 18. Changes and modifications had been made to a previously approved test program which required additional information from the applicant before we could complete our review. This information was requested from the applicant by letters dated April 1 and April 30, 1985, from A. Schwencer, NRC, to W. J. Cahill, Gulf States Utilities Company (GSU). The applicant responded with the necessary information in a letter from J. E. Booker, GSU, to H. R. Denton, NRC, dated May 15, 1985. This information is to be confirmed by FSAR amendment. We have reviewed the revised Initial Plant Test Program and find it acceptable.

In the May 15, 1985 letter, the applicant took exception to the provision for two hour testing at 110 percent of rated load in section C 2.a.(3) of Regulatory Guide 1.108, Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants. The acceptability of this exception and the applicant's proposed test program for the Transamerica Delaval Diesel Generators at River Bend will be addressed separately by the TDI Project Group in a staff SER.

The review was performed with the assistance of Battelle Pacific Northwest Laboratories. The PSRB reviewer is Richard Becker (X29689). The reviewer is not aware of any "Differing Professional Opinions" with respect to the results of the review.

Don H. Beckham, Acting Deputy Director
Division of Human Factors Safety

cc: W. Butler
S. Stern
R. Gruel, PNL

ENCLOSURE 1

SSER INPUT FOR RIVER BEND

CHAPTER 7

INSTRUMENTATION & CONTROLS

7.2.2.6 Isolation Devices

Isolation devices are used between safety related and non-safety related circuits to protect the safety related circuits from damage due to electrical faults that could occur within the non-safety related circuits. Isolation devices are also used between redundant safety related circuits to prevent electrical faults from adversely affecting circuits from redundant channels/divisions (i.e., the effects of the fault are contained on one side of the isolation device). The applicant has confirmed that only two types of isolation devices are used at River Bend. These are: 1) Potter Brumfield MDR relays (these are rotary type relays providing coil-to-contact isolation), and 2) optical isolator assemblies (the assemblies consist of input and output printed circuit cards on either side of a ceramic barrier; polished quartz crystal rods embedded in the ceramic material transmit light across the barrier). The applicant confirmed that relay contact-to-contact isolation is not used at River Bend, and that Section 7.1.4.1 of the FSAR will be revised accordingly.

The staff audited the test plans and procedures used to demonstrate the qualification of both the MDR relays and the optical isolators as acceptable isolation devices. The acceptance criteria for both types of devices was found to be acceptable (i.e., upon application of a fault to one side of the device, no degradation occurs to circuits on the opposite side of the device). The applicant has stated that the MDR relays and optical isolation devices are seismically and environmentally qualified for their safety related applications at River Bend. These devices are discussed in detail below.

All MDR relays used as isolation devices at River Bend are mounted within metal enclosures containing a metal barrier that separates the coil section of the relay and its associated wiring from the contact section of the relay and its associated wiring. The barrier is grounded, and is designed to prevent faults at the output (contacts) of the device from propagating to the input (coil) of the device. Since the entire relay is housed in a metal enclosure, external faults should not compromise the isolation function of the relay or influence signal integrity.

Complete functional tests were performed on the MDR relays before and after the relays underwent seismic and environmental qualification testing. The functional test program included contact resistance checks, pickup/dropout voltage testing, contact transfer/delay time tests, dielectric strength/insulation resistance tests and contact current rating tests. The MDR relays tested successfully passed all functional tests. The dielectric strength/insulation resistance test and the contact current rating test are further discussed below.

The dielectric strength/insulation resistance test consisted of applying 1000 Vac for one minute between the normally closed contacts (wired in series) and the relay chassis (ground), first with the relay coil de-energized, and subsequently with the coil energized (120 Vac, 60 Hz). The test voltage was applied using a "Hipotronics Testor" that includes a light and alarm which are activated if leakage current exceeds 5000 microamps. After the 1000 Vac was removed, 500 Vdc was applied across the same terminals and the insulation resistance to ground was measured. In each case, the insulation resistance was greater than 50,000 megohms. This test demonstrates that no arcing or

damage to the relay occurs and that there is no insulation resistance breakdown (including carbon traces) upon application of the 1000 Vac.

The contact current rating tests consisted of cycling (energizing and deenergizing) the relay five times in succession for various output (contact) load configurations, including 115 Vac and 15 amps (load current through the relay contacts). The voltage drop across the contacts was measured before and after the test. The test results showed no significant increase in the voltage drop across the relay contacts (the increase was less than 2 millivolts for the 115 Vac/15 amp case). The relay single contact current rating at 115 Vac is 10 amps. This test demonstrates that a credible fault current applied to the output (contact) side of the relay will not result in relay damage, and that the fault will not propagate to the input (coil) side of the device. The staff considers 115 Vac/15 amps to be the minimum credible fault voltage/current acceptable for qualification of components as acceptable isolation devices.

Based on the results of the above tests and the relay mounting configuration (metal enclosure with barrier between the coil and contact portions of the device), the staff concludes that the Potter Brumfield MDR rotary type relays (model MDR-4130-1) as installed at River Bend are acceptable isolation devices for use between redundant safety related circuits, and between safety related and non-safety related circuits.

The optical isolator assemblies contain either 4 or 8 input and output card pairs, with approximately 4 to 12 individual isolators per card pair, depending upon the specific application. Quartz rods (light pipes) transmit

signal information across the ceramic isolation barrier provided between the input cards and the output cards. All cards on a given side of the isolation barrier are powered from the same electrical division. Maximum credible voltage/current tests and 5000 Vac card isolation tests were performed on the optical isolator assemblies. These tests are discussed below.

The maximum credible voltage/current test was performed for the following input/output card pairs:

- o Field Contact Input/High Level Output
- o Field Contact Input/5V Logic Output
- o Field Contact Input/12V Logic Output
- o Field Contact Input/Floating Low Level Output
- o High Speed Input/High Speed Output
- o Analog Input/Analog Output
- o Logic Input/12V Logic Output

The maximum credible fault voltage and current values were determined by identifying the largest voltages present within plant instrumentation cabinets/panels/control boards and the largest associated branch fuses/circuit breakers. These values for River Bend are 125 Vac/30 amps and 140 Vdc/30 amps. The fault voltages were applied to each input/output card pair in each of the following test circuit configurations:

1. fault voltage applied between each input terminal (wired in parallel) and ground (signal returns and the isolator assembly housing).

2. fault voltage applied in the transverse mode between the input terminals (wired in parallel) and the returns (wired in parallel).

3. fault voltage applied between each output terminal (wired in parallel) and ground.

4. fault voltage applied in the transverse mode between the output terminals (wired in parallel) and the returns (wired in parallel).

The fault voltages were applied for a one minute duration for each test configuration. For each test case, the opposite side of the isolation barrier was monitored (using a memory oscilloscope) to detect any perturbations that might occur. The acceptance criteria for all tests was that no fault source voltage appear on the opposite side of the isolation barrier. The fault voltages were applied via fused (30 amp) connections; no fuses failed during the tests. The test results showed there were two cases where a voltage perturbation occurred on the opposite side of the isolation barrier, due to arcing from the input cards to the assembly chassis (common to both sides of the isolation barrier), causing a momentary increase in ground potential. The two cases were the high speed card pair and the analog card pair. The amplitude of the perturbations was less than 2 volts and the duration was less than 100 milliseconds. Both cases involved test configuration 1 above and the application of 140 Vdc. The staff does not consider these perturbations significant with respect to impairing the capability of the optical isolator assembly to perform its isolation function. Following the tests, standard production/operability tests (preprogrammed automated tests) were performed on the isolator cards that were located on the opposite side of the isolation barrier

from where the faults were applied. All cards were tested successfully (i.e., remained operable following the fault tests). Isolator cards to which the faults were applied were destroyed during the fault tests.

The 5000 Vac card isolation test consisted of applying 5000 Vac between all input terminals (wired in parallel) and the isolator assembly chassis (ground) for the same input/output card pairs listed above for the credible fault tests. Subsequently, a standard production/operability test was performed on the output cards to verify that the isolation provided between the input and output sides of the assembly is sufficient to prevent the 5000 Vac applied to the input side of the device from impairing the function of the output cards. The above test was repeated with the 5000 Vac applied to the output cards and a production/operability test performed on the input cards. For all cases the acceptance criteria (i.e., no damage occurring to any devices on the opposite side of the isolation barrier) was satisfied.

Based on its review, the staff concludes that the MDR relays and optical isolator assemblies (models 133D9947 and 147D8804) used to provide physical and electrical isolation between redundant safety related circuits, and between safety related and non-safety related circuits, satisfies the applicable acceptance-criteria (i.e., an abnormal/fault voltage/current on one side of the isolation device does not affect the functional capability of circuitry on the opposite side of the device), and therefore, are acceptable. This resolves Confirmatory Issue #6 as listed in Section 7.1.4.2 of the River Bend SER. It should be noted that this evaluation does not include those isolation devices

used in the emergency response and information system (ERIS) or the digital radiation monitoring system (DRMS). These devices are discussed in Sections 7.7.2.3 and 7.6.2.7 of the SER.

7.3.2.7 Initiation of ESF Supporting Systems

The River Bend design includes safety related air conditioning units and unit coolers (listed below) which provide ventilation and cooling for rooms/areas containing safety related equipment.

Unit Cooler	Area Serviced
1HVC*ACU1A+	Control Room
1HVC*ACU1B+	Control Room
1HVC*ACU2A+	Switchgear/Battery/Cable Areas
1HVC*ACU2B+	Switchgear/Battery/Cable Areas
1HVC*ACU3A+	Chiller Equipment Room
1HVC*ACU3B+	Chiller Equipment Room
1HVR*UC1A++	Containment
1HVR*UC1B++	Containment
1HVR*UC2	RWCU Pump Room
1HVR*UC3	RPCCW and CRD Areas
1HVR*UC4	Auxiliary Building General Area
1HVR*UC5	HPCS Pump Room
1HVR*UC6	RCIC & RHR Division 1 Equipment Room
1HVR*UC7	MCC Areas
1HVR*UC8	Main Steam Pipe Tunnel, North
1HVR*UC9	RHR Division 2 Equipment Area
1HVR*UC10	MCC Areas
1HVR*UC11A	East SGTS Area/West Equipment Area
1HVR*UC11B	East SGTS Area/West Equipment Area

+ These air conditioning units start automatically following a LOCA signal [i.e., reactor vessel low water level (level 1) and/or high drywell pressure] and load sequence permissive if power is available to the respective emergency buses and an associated chilled water pump is running.

++ These unit coolers start automatically on a LOCA signal if power is available at the respective emergency buses.

Unit coolers 1HVR*UC2 through 1HVR*UC10 and 1HVR*UC11A&B do not receive automatic start signals. These unit coolers must be manually started from the control room. Because some of the unit coolers provide cooling for rooms containing engineered safety features (ESF) equipment, the staff raised concerns that the unit coolers did not automatically start in response to system level initiation signals (manual or automatic) for the respective ESF systems. The Technical Specification definition of OPERABILITY states that in order for a

system, subsystem, train, component, or device to be considered operable, that it must be capable of performing its function, and that all necessary attendant auxiliary/supporting equipment necessary for the system, subsystem, train, component, or device to perform its function (e.g., electrical power, cooling or seal water, lubrication, etc.) must also be capable of performing their related support function(s). It is the staff's understanding that room cooling is required for ESF equipment to operate properly. The staff was also concerned that ESF pump room high temperature conditions were not adequately annunciated in the control room.

The applicant has stated that unit coolers 1HVR*UC2 through 1HVR*UC10 and 1HVR*UC11A&B will be run continuously, and therefore, automatic initiation of the unit coolers is not required. Control room annunciation is provided for certain conditions resulting in unit cooler failure. Examples are cooling water supply valves closed and loss of power. However, the staff was concerned that a unit cooler failure could go undetected. All conditions that could result in unit cooler failure are not/cannot be annunciated. To resolve this concern, the applicant has included surveillance of unit coolers 1HVR*UC2 through 1HVR*UC10 and 1HVR*UC11A&B as part of the control building and auxiliary building daily logs, with the exception of 1HVR*UC8. This surveillance consists of plant personnel physically going to the individual unit cooler locations and verifying air flow through the coolers. The staff concludes that the daily surveillance is sufficient to ensure that a unit cooler failure does not go undetected.

Unit cooler 1HVR*UC8 provides cooling to the north main steam pipe tunnel. This is a high radiation area which cannot be accessed for surveillance during

operation. The applicant has indicated that the area served by 1HVR*UC8 is a small area containing several motor operated valves and containment isolation valves. The unit cooler is provided to keep the temperature in this area below the temperature limit of 122°F. The temperature has been analyzed to go as high as 244°F on unit cooler failure. River Bend Technical Specification 3/4.7.8 (Area Temperature Monitoring) requires that if the temperature exceeds the temperature limit by more than 30°F, that the temperature be restored to within the limit within 4 hours, or that all equipment in the affected area be declared inoperable. Redundant high area temperature alarms are provided in the control room from the safety related leakage detection system (LDS) if the temperature in the north main steam pipe tunnel reaches 135°F. The staff concludes that adequate provisions have been taken to ensure that the temperature in the north main steam pipe tunnel area served by 1HVR*UC8 remains within acceptable limits.

Based on the above, the staff concludes that automatic initiation of unit coolers 1HVR*UC2 through 1HVR*UC10 and 1HVR*UC11A&B is not required, and that the combination of periodic surveillance and area temperature alarms is sufficient to ensure unit cooler operability, and therefore, the operability of the associated ESF equipment. This resolves Confirmatory Issue #10 as listed in Section 7.1.4.2 of the River Bend SER. It is noted that air conditioning units 1HVC*ACU1A&B, 1HVC*ACU2A&B, and 1HVC*ACU3A&B are also verified to be operable daily in accordance with surveillance required by the control building daily log. The areas served by these unit coolers are commonly accessed during plant operation. In addition, alarms are received in the control room on inlet filter high differential pressure and high discharge temperature for 1HVC*ACU1A&B and 1HVC*ACU2A&B. River Bend Technical Specification 3/4.7.8 also contains temperature limits for those areas served

by all unit coolers listed above, with the exception of the containment unit coolers (1HVR*UC1A&B). The containment unit coolers are provided with discharge temperature indication and low flow alarms in the main control room.

7.6.2.5 Isolation Between the Neutron Monitoring System and Rod Control and Information System

The rod pattern control system (RPCS) is a subsystem of the rod action control system (RACS) portion of the rod control and information system (RCIS). The RPCS is a redundant system (Divisions 1 and 2) designed to limit the consequences of a rod drop accident by restricting control rod movement (i.e., initiating rod blocks) to within preestablished patterns. The RPCS is powered from the 120 Vac emergency safeguards buses. RPCS Division 1 circuitry is located in RACS cabinet 1H13*P651 in the control room. This cabinet also receives inputs from Divisions 1 and 4 of the neutron monitoring system (NMS), and inputs from non-safety related sources (e.g., the operators rod control module and the refuel platform). RPCS Division 2 circuitry is located in RACS cabinet 1H13*P652, which receives inputs from NMS Divisions 2 and 3 and from non-safety related sources. NMS Divisions 1 and 3 are powered from reactor protection system (RPS) bus A, and NMS Divisions 2 and 4 are powered from RPS bus B. The staff's initial review raised concerns that the isolation provided between the NMS and the RCIS, and between non-safety related circuits and safety related circuits within the RACS cabinets may not be sufficient to prevent electrical faults from affecting redundant divisional circuits.

The staff has subsequently reviewed all inputs to the RACS cabinets, both safety related and non-safety related. All inputs to the RACS cabinets are buffered using optical isolation devices. These devices are the light emitting diode/photo transistor type mounted on printed circuit (PC) cards. Where RACS inputs are from the same division (e.g., NMS, mode switch, turbine first stage pressure, rod position multiplexers, scram discharge instrument

volume level), only the buffering is provided. Where the inputs are from a redundant division (NMS) or from a non-safety related source, electrical isolation using qualified quartz rod isolator modules (discussed in Section 7.2.2.6 of this report) is provided in addition to the buffering. In addition, RACS inputs from the RCIS itself (e.g., from the rod gang drive system cabinet and the operator's control module) are isolated using the quartz rod modules.

The use of qualified isolation devices at the RACS cabinet boundary prevents electrical faults in non-safety related circuits external to the cabinets from affecting internal safety-related circuits. The staff has concluded that the isolation provided between the NMS and the RCIS is sufficient because 1) in addition to the buffering, coil-to-contact isolation is provided, 2) all other inputs to the RACS cabinets are buffered/isolated as discussed above, and 3) should a fault within the RCIS degrade the NMS, redundant and diverse instrumentation is available to accomplish all required protective functions (reactor scram and rod block). This resolves Confirmatory Issue #18 as listed in Section 7.1.4.2 of the River Bend SER.

7.7.2.1 High Energy Line Breaks and Consequential Control Systems Failures

The applicant was requested to determine whether multiple non-safety related (control) systems failures, resulting from the adverse environment created by a high energy line break (HELB), could result in consequences more severe than previously considered in the FSAR Chapter 15 accident analyses. This concern is addressed in IE Information Notice 79-22. The applicant has performed an analysis of the River Bend Station control systems and high energy piping, and concluded that for all postulated HELBs, the consequences of the break coupled with the effects of all postulated non-safety related equipment failures, are bounded by (i.e., are less severe than) the consequences of the events analyzed in Chapter 15 of the River Bend FSAR. Details of the applicant's analysis and the staff's evaluation of the analysis are provided below.

The applicant identified all non-safety related/control systems that could affect reactor critical parameters (e.g., water level, pressure, critical power ratio). Systems with no controlling functions and systems that do not interface with reactor operation or reactor parameters were eliminated from the analysis. Examples of these systems are lighting, communications, annunciators, the computer, refueling equipment, ventilation systems, mechanical and structural systems (e.g., structural steel, tanks, cranes), and electrical systems which will not impact reactor critical parameters on loss of power. For those systems which can affect reactor critical parameters, the applicant compiled a list of system components to be included in the HELB analysis. Mechanical components (e.g., tanks and pipes) and instruments providing dedicated inputs to the computer, indicators, alarms, or position status information were excluded from the list. Instrument sensing lines, and position switches that

are interlocked with other equipment were included in the analysis. Motor control centers (MCCs) were considered for analysis, however, since none of the remaining components were mounted at MCCs or powered directly from a MCC, MCCs were eliminated from the analysis. In general, the final list of non-safety related/control system components that could affect reactor critical parameters consisted of valves, switches, transmitters, and controllers.

The applicant then identified all high energy lines at River Bend using the criteria for high energy lines established in Section 3.6 of the FSAR. High energy lines are defined as those which are in operation or maintained pressurized during normal plant conditions where the maximum temperature of the fluid in the line exceeds 200°F or the maximum pressure of the line exceeds 275 psig. High energy lines that operate above these limits for less than 2% of the time are classified as moderate energy lines and were excluded from the analysis. High energy lines which are less than 1-inch in diameter were also excluded. The exclusion of these lines is acceptable because 1) breaks of moderate energy fluid system piping are not postulated to occur in accordance with Branch Technical Position MEB 3-1 (see Section 3.6.2 of the Standard Review Plan), and 2) the environmental effects of breaks of lines 1-inch in diameter or smaller are less severe than for larger lines considered in the analysis (typically, these are instrument sensing lines whose failure can be detected from the abnormal behavior of instruments associated with the broken line). Instrument line failures resulting from breaks in larger high energy lines were considered in the analysis.

The applicant performed a plant walkdown using maps of the reactor, turbine, and auxiliary buildings in order to subdivide the plant into HELB zones. Each zone is a separate area of the plant which is bounded by walls, ceiling, floors, etc. such that the environmental effects of a HELB in a given zone are confined to that zone, or in some cases, also to adjacent zones. Certain zones extend between elevations because of open floor grating or hoist openings between elevations.

Next, the applicant determined those zones where components that can affect reactor critical parameters are located. The high energy lines identified were then assumed to break at all locations (zones) where the non-safety related/control components are located. The applicant used a "sacrificial approach" when analyzing the effects of a pipe break in a given zone (i.e., all non-safety related/control components in that zone were assumed to fail). All component failure modes were considered to determine the worst case failures for all components. Where a HELB could affect non-safety related/control components in more than one zone (e.g., a break within a small cubicle can conceivably blow out the door and the environmental effects of the break could affect components in the adjoining larger volume zone), all components in all affected zones were considered to fail in their worst states. The sacrificial approach covers all potential component failure mechanisms (i.e., pipe whip, jet impingement, humidity, temperature, pressure, and radiation) since this approach assumes that the break will adversely impact all components in the respective zone(s).

The applicant has analyzed the worst case combined effects of each HELB and all consequential non-safety related/control systems failures. Where the

worst case failure mode for a component was not readily discernable, all failure modes and their consequences were analyzed. The consequences of these events were then compared to the accident and transient analyses presented in Chapter 15 of the River Bend FSAR. The worst case event was determined to be a break in a moisture separator vent and drain high energy line in the turbine building which results in a partial loss of feedwater heating. The failure of non-safety related/control components in this zone can result in a further loss of feedwater heating and a resultant increase in reactor power, and may cause a turbine trip. The applicant determined that if the turbine trip occurs at a reactor power level elevated from the initial operating value, that the reactor may experience a change in critical power ratio greater than that considered in the FSAR Chapter 15 analyses. However, subsequent analysis performed by the applicant has demonstrated that the effects of this accident event, including consideration of a single active failure in a mitigating safety system, are bounded by the Chapter 15 analyses. The applicant has determined that the combined consequences of all other HELBs and consequential non-safety related/control system component failures are also bounded by the River Bend accident and transient analyses presented in Chapter 15 of the FSAR.

Based on a detailed review of the applicant's analysis of HELBs and consequential non-safety related/control system component failures for several different zones (including the worst case event zone), the staff has concluded that the methodology used and the results of the analysis performed by the applicant are acceptable. This resolves Confirmatory Issue #21 as listed in Section 7.1.4.2 of the River Bend SER.

ENCLOSURE

RIVER BEND SUPPLEMENTAL SAFETY EVALUATION REPORT

8.0 ELECTRIC POWER SYSTEMS

8.3 Onsite Emergency Power Systems

8.3.1 AC Power Systems

In section 8.3.1 of the River Bend SER the staff stated it would confirm the correction of a typographical error on FSAR Table 8.3-2 regarding deenergization of the LPCS or RHR pump in two hours and confirm that procedures exist to control this. The staff also stated that it would evaluate a synopsis of the Division I and II diesel generator qualification test results when they are available. The Division I and II diesels are manufactured by Transamerica Delavel, Inc. (TDI). The staff has reviewed the qualification of similar diesels at Shoreham with respect to IEEE 387 and R.G. 1.9 and has found them acceptable. The TDI diesels, however, are also the subject of a detailed generic review which was initiated as the result of failures experienced on the Shoreham units. The results of the generic review will, therefore, govern for qualification of the River Bend units. These results for River Bend are reported separately in this report.

Amendment 20 to the FSAR states that the Division I and II diesel generators were each given a load capability test at their rated load of 3500 kW for 24 hours and that this satisfies the 110 percent overload requirement of R.G. 1.108, paragraph C.2.a(3) because it is more than 110% of the machines qualified load. The staff does not agree that testing the machine to 110% of the maximum qualified load that it will carry meets the R.G. 1.108 requirement. The requirement is to test the machine to 110% of its continuous rating. The

staff, however, is making an exception to this requirement for the Division I and II diesels at River Bend because of the concern identified in the TDI diesel generic evaluation. The staff has determined that the diesels are capable of delivering 3,130 kW continuously and load testing should be limited to this value. These tests while they do not strictly adhere to the guidelines of R.G. 1.108 do adequately demonstrate the DG capability to assume the actual load requirements for accidents and transients as described below. The remaining test requirements in R.G. 1.108 will be conducted on the Division I and II diesel generators as prescribed in the Regulatory Guide. Because the Division III diesel is not a TDI unit, it will be tested in accordance with all the requirements of R.G. 1.108.

With regard to the deenergization of the LPCS or RHR A pump, the applicant has since revised the entire loading profile on the diesel generator units which the staff had originally reviewed. The most recent diesel generator loading for Divisions I and II was submitted by the applicant in FSAR amendment 21. The applicant has reduced the loading on these Divisions from an original maximum of 3,724 kW down to the current maximum of 2,886 kW to demonstrate adequate load margin on their TDI diesel generators. They have accomplished this through a combination of transferring loads (Standby Service Water Pump 2C to Division III), delaying the start of loads, manually deenergizing loads, eliminating loads, and assuming reduced power input to loads.

The kilowatt demand of each load on the diesel generators was calculated by using brake horsepower and the efficiency data supplied by vendors of the respective equipment. Operator action is assumed at two hours into the LOCA load profile to shed automatically sequenced loads and load other required manually actuated loads. Motor operated valves are assumed to have completed their stroke by 10 minutes into the load sequence. The staff has reviewed the proposed loading profile of the Division I and II diesel generators and finds it acceptable. The load carrying capability of the Division I and II diesel generators is addressed as part of the TDI generic review. The evaluation of these units is covered elsewhere in this report.

As stated above, the Standby Service Water Pump 2C will be moved to the Division III (HPCS) diesel generator. Associated with this change a Standby Service Water Pump Room Vent Fan and Standby Service Water Pump Discharge Valve will also be energized from Division III. All the Division III loads will be simultaneously loaded onto the diesel generator with the exception of the Standby Service Water Pump Motor which will be sequenced to operate at 30 seconds after the diesel generator circuit breaker closes. The maximum load on the diesel generator will be 2,393 kW which is less than the diesel generator continuous rating of 2,600 kW. The staff has reviewed the revised loading of the Division III diesel generator and finds it acceptable.

In section 8.3.1 of the staff's original evaluation, it was stated that all Class 1E motors at River Bend are capable of starting and accelerating their driven equipment with 70% of motor nameplate voltage applied to motor terminals without affecting performance or equipment life. FSAR amendment 19 has changed the 70% figure to 80%. The staff was concerned that, if the 80% figure applied to all Class 1E motors, the motors would not be capable of starting during degraded voltage conditions. This is based upon the applicant's March 5, 1984 letter which provided a voltage profile that showed less than 80% starting voltage available to start major Class 1E motors under degraded voltage conditions. In FSAR amendment 21 the applicant clarified that only the motors driving air compressors 1LSV*C3A and 1LSV*C3B require 80% voltage to start, and calculations have determined that the minimum starting voltage available at the motor terminals is 89.63%. The remaining Class 1E motors still require only 70% voltage to start. This resolves the staff's concern on this issue and is acceptable.

8.3.2 <u>DC Power Systems</u>

In amendment 19 to the FSAR the applicant deleted a listing of much of the Division III instrumentation which is used to monitor the status of the Division III dc system and which the staff had previously reviewed and found acceptable. It appeared that this might have been an unintentional editorial

error. FSAR amendment 21 reinstated the instrumentation which had been deleted. This, therefore, is acceptable.

In a letter dated July 15, 1985, the applicant provided a proposed FSAR amendment which revised the Division III (HPCS) battery loading profile and changed the resulting battery endurance from four hours to two hours. The staff has reviewed these changes and finds them acceptable. The staff will ensure that the River Bend Technical Specifications incorporate the revised information.

8.4 Other Electrical Features and Requirements for Safety

8.4.1 Adequacy of Station Electric Distribution System Voltages

(1) In section 8.4.1 (1) of the staff's original evaluation the staff stated it would confirm the adequacy of the final relay setpoints for the second level undervoltage protection. In a letter dated July 24, 1985, the applicant provided the setpoint calculations for the first and second levels of undervoltage protection. The setpoints for the Division I and II vital buses are 2970 V (74.3% of equipment rated voltage) for the first level and 3740 V (93.5% of equipment rated voltage) for the second level. The setpoints for the Division III vital bus is 3045 V (76.1% of equipment rated voltage) for the first level and 3777 V (94.4% of equipment rated voltage) for the second level. The staff has reviewed these setpoints and their tolerances provided in the applicant's letter and finds them acceptable.

Amendment 19 to the FSAR provided figure revisions which indicate the Division III undervoltage protection logic is not arranged in the 2-out-of-3 coincidence logic as described in the applicant's March 5, 1984 letter and reported in our original evaluation. FSAR amendment 21 provided a revised response to the description of the Division III (HPCS) first and second levels of undervoltage protection. The first and second level undervoltage protection scheme senses voltage at the incoming side of the

normal supply breaker. The first level of undervoltage protection is arranged in a 1-out-of-2 logic with a time delay of approximately two seconds.

The second level of undervoltage protection is arranged in a 2-out-of-2 coincidence logic and utilizes two separate time delays. The first is approximately 10 seconds (to override motor starting transients). Following this delay, an alarm in the main control room alerts the operator to the degraded condition. The subsequent occurrence of a LOCA signal immediately separates the Division III bus from the offsite power system. The second delay is approximately 60 seconds. After this delay, if the operator has failed to restore adequate voltages, the Class 1E system is automatically separated from the offsite power system. The 2-out-of-2 coincident logic used for the second level undervoltage protection allows one relay to be taken out of service for test and calibration while an effective 1-out-of-1 protective logic is retained. The staff finds that the design of the second level undervoltage protection as described above satisfies the provisions of PSB-1 and is, therefore, acceptable.

(4) The staff indicated in section 8.4.1(4) of its original evaluation that it would confirm the adequacy of the applicant's verification tests. These tests have not yet been completed. The staff will review and provide its confirmation of the acceptability of these tests and their results in a supplement to this report when the results are available but no later than prior to startup from the first refueling outage.

8.4.2 Containment Electrical Penetrations

Amendment 19 and 20 to the FSAR provided some revisions to the description of the containment electrical penetration protection at River Bend. For low voltage control circuits, a category of circuits was added that had been analyzed and found not to require backup protection. These circuits are current transformer leads used on differential protection circuits, and trip

coil circuits in circuit breakers. In a letter dated July 24, 1985, the applicant provided justification for the lack of protection on these circuits. The current transformer leads on differential protection circuits are acceptable because a high current exists on these circuits only momentarily when a fault is sensed and is quickly cleared by the differential protection circuit. An open circuit on the current transformer secondary which could cause high voltages will also cause a trip of the protection circuit which will in turn eliminate the overvoltage. The lack of redundant protection on trip coil circuits is acceptable because these circuits are fed from an ungrounded 125 Vdc power supply and the portion of the circuit passing through the penetration is confined to only one leg (positive or negative) of the power supply. The only type of failure the penetration circuit would be exposed to is an electrical ground which would not cause fault current to flow unless there was a simultaneously existing fault on the opposite leg of the power supply. This is unlikely to occur because a ground detection alarm is provided on the 125 Vdc system which alerts the operator to the existence of the first ground on the system so that he may track down and remove it to maintain the system ungrounded.

Another revision to the penetration protection is the addition of a category of low voltage control circuits which are deenergized during plant operation. With the exception of the ERF system (portable equipment installed during shutdown), the equipment in this category will all be listed in the River Bend Technical Specification to ensure they remain deenergized during plant operation. If the circuits have provisions for locking them in the deenergized state they will also be locked open. These provisions are acceptable. The other remaining electrical penetration revisions made in FSAR amendments 19 and 20 have been reviewed and are also acceptable.

8.4.5 Physical Identification and Independence of Redundant Safety-Related Electrical Systems

In section 8.4.5 of the staff's original evaluation, the staff stated that 4.16 kV/13.8 kV cabling in conduit is not routed in close proximity to Class 1E ladder-type trays except where the cables exit from the subject tray. This statement was based on a similar statement in Chapter 8 of the FSAR. Amendment 20 to the FSAR has subsequently deleted this statement. The staff has reviewed the separation details for these circuits contained in River Bend drawings 12210-EE-34ZE-7 and 12210-EE-34ZH-6 and finds that they comply with the requirements of IEEE Standard 384 and R.G. 1.75 and are, therefore, acceptable.

In a previous supplement, the staff evaluated the use of red and blue-colored jacketed cables in unscheduled non-Class 1E circuits (these colored cables are normally only used to identify Class 1E circuits), and found them acceptable with the restrictions outlined in amendment 16 to the FSAR. Amendment 20 to the FSAR has added additional categories where these cables are used. These are in direct burial cable installations and inside the makeup water intake structure, in various types of raceways, where there are only nonsafety-related circuits. The FSAR states that there are no safety-related Category I circuits at these locations, and no safety-related circuits are installed in direct burial cable trenches. The staff finds that these exceptions to cable color coding will not decrease the effectiveness of the color coding system used at River Bend and are, therefore, acceptable.

8.4.6 Nonsafety-Related Loads on Emergency Sources

In a previous supplement the staff stated a need to review the applicant's evaluation with regard to the acceptability of non Class 1E slide wire transducers and limit switches. In a letter dated July 5, 1985, the applicant provided his evaluation. For the slide wire transducers, a qualified resistor limits the available fault current to a small value which has no detrimental effect on the Class 1E power supply should a short or ground occur on the

unqualified transducer. For the limit switches, a short or a ground on the limit switch is the same as if the switch were closed which also has no detrimental effect on the Class 1E power supply. Both the slide wire transducer and limit switch circuits as designed are, therefore, acceptable.

In FSAR amendment 20 the applicant added non-Class 1E motor heaters to the list of non-Class 1E loads powered from Class 1E power supplies. The motor heaters are powered from a Class 1E 120 V panelboard. There is a single Class 1E circuit breaker in the 120 V feed to the motor heater. In a letter dated July 5, 1985, the applicant stated that for Westinghouse motors the heater is qualified Class 1E and for Reliance motors the heaters are also considered to be Class 1E. For Seimens-Allis motors, the applicant has committed to install a second overcurrent protection device in the 120 V feed to the motor heater. In the interim, he has committed to keep these circuits deenergized. We require that when the second overcurrent protective device is installed the circuit breakers in the circuit be listed in the River Bend Technical Specifications and they be periodically tested. With those provisions, the staff finds this item acceptable.

ENCLOSURE 1

HUMAN FACTORS ENGINEERING BRANCH

DETAILED CONTROL ROOM DESIGN REVIEW

SUPPLEMENTAL SAFETY EVALUATION REPORT

FOR

RIVER BEND STATION UNIT 1

DISCUSSION

The purpose of this SER Supplement is to closeout the open licensing issues of the Detailed Control Room Design Review (DCRDR) required by Supplement 1 to NUREG-0737. The Lawrence Livermore National Laboratory (LLNL) Technical Evaluation Report (TER) dated January 29, 1985 and the LLNL Supplemental Technical Evaluation Report (STER) dated June 28, 1985 provide the evaluation of the River Bend Station Unit 1 DCRDR up to and including the GSU Supplemental Summary Report (SSR) No. 1 dated May 14, 1985. NRC staff reviewed the SSR No. 2 dated June 12, 1985 which resolved the concerns expressed in Appendix B of the enclosed LLNL STER, and discussed the resolutions with the LLNL staff. The NRC staff concurs in the technical evaluations and conclusions contained in the STER, which is enclosed.

The DCRDR open issues which are identified in the conclusions section of the SER input dated March 20, 1985, are closed out based on the following acceptable responses provided by GSU:

1. Confirmed the continued participation of human factors specialists in the remaining DCRDR activities

2. Submitted additional task analysis documentation results discussed in the SER input (March 20, 1985) under Function and Task Analyses

3. Confirmed that the remaining control room survey items have been completed and the submittal of acceptable resolutions and implementation schedules for HEDs identified

4. Provided acceptable responses to the specific concerns regarding resolution of the HEDs identified in Appendices A and B to the Technical Evaluation Report (January 29, 1985) enclosed with the staff's SER input (March 20, 1985)

5. Confirmed that all control room modifications resulting from the DCRDR have been verified to assure they have provided the expected corrections and do not introduce new HEDs

Although GSU committed to implementing corrective actions for a number of HEDs prior to licensing, the NRC does not plan to confirm that all of these actions have been completed prior to issuing the low power license. However, the NRC will confirm that all actions proposed to correct HEDs prior to licensing and prior to exceeding 5 percent rated power have been completed before a full power license is issued. All but nine of approximately 325 HEDs will be corrected prior to exceeding 5 percent power. The nine HEDs will be corrected during the first refueling outage. We have determined that the confirmation of actions required to correct certain HEDs prior to

licensing could be deferred until prior to issuance of a full power license without affecting safe operation of the plant. The identification of all HEDs requiring corrective action and the accepted GSU proposed schedules for implementing the actions are contained in the RBS DCRDR Summary Report dated October 31, 1984 and Supplements dated May 14, and June 12, 1985.

CONCLUSION

Based on our review of the RBS Program Plan, DCRDR Summary Report and Supplements and an on-site, in-progress audit, we have concluded that except for completing the implementation of corrective actions for certain HEDs, GSU has satisfactorily completed its DCRDR for River Bend Station Unit 1 in accordance with the requirements of Supplement 1 to NUREG-0737. The NRC will verify implementation of actions to correct certain HEDs prior to exceeding 5 percent power and prior to start-up after the first refueling outage in accordance with commitments made in the Summary Report and Supplements dated October 31, 1984, May 14 and June 12, 1985 respectively.

REFERENCES

1. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," May 1980; Revision 1, August 1980.

2. NUREG-0737, "Clarification of TMI Action Plan Requirements, Supplement 1," December 1982.

3. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" Section 18.1, Rev. 0 and Appendix A to Section 18.1, Rev. 0, September 1984.

4. Letter from A. Schwencer, NRC, to W. Cahill, Jr., transmitting staff comments on River Bend Station Control Room Design Review Program Plan, April 25, 1984.

5. Letter from J. E. Booker, GSU, to H. R. Denton, submitting the River Bend Station Detailed Control Room Design Review Program Plan, January 31, 1984.

6. Letter from A. Schwencer, NRC to W. Cahill, Jr., transmitting the results of the In-Progress Audit of the River Bend Station Detailed Control Room Design Review, October 11, 1984.

7. Letter from J. E. Booker, GSU, to H. R. Denton, submitting the River Bend Station Detailed Design Review Summary Report, October 31, 1984.

8. Letter from J. E. Booker, GSU, to H. R. Denton, submitting additional information on the River Bend Station Detailed Control Room Design Review, January 23, 1985.

9. Technical Evaluation Report of the Detailed Control Room Design Review for Gulf States Utilities Company River Bend Station, prepared by Lawrence Livermore National Laboratory, January 29, 1985.

10. Letter from J. E. Booker, GSU, to H. R. Denton, submitting the Detailed Control Room Design Summary Report Supplement for River Bend Station, May 14, 1985.

11. Letter from J. E. Booker, GSU, to H. R. Denton, submitting Supplement No. 2 to the River Bend DCRDR Summary Report, June 12, 1985.

12. Supplemental Technical Evaluation Report for the River Bend Station DCRDR Supplemental Report, prepared by LLNL, June 28, 1985.

SUPPLEMENTAL TECHNICAL EVALUATION REPORT OF THE SUMMARY REPORT SUPPLEMENT No. 1 TO THE DETAILED CONTROL ROOM DESIGN REVIEW FOR GULF STATES UTILITIES COMPANY RIVER BEND STATION

JUNE 28, 1985

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Lawrence Livermore National Laboratory
for the
United States
Nuclear Regulatory Commission

TECHNICAL EVALUATION REPORT
OF THE
SUMMARY REPORT SUPPLEMENT
TO THE
DETAILED CONTROL ROOM DESIGN REVIEW
FOR
GULF STATES UTILITIES COMPANY
RIVER BEND STATION

1. BACKGROUND

Licensees and applicants for operating licenses shall conduct a Detailed Control Room Design Review (DCRDR). The objective is to "improve the ability of nuclear power plant control room operators to prevent accidents or cope with accidents if they occur by improving the information provided to them" (NUREG-0660, Item I.D.). Supplement 1 to NUREG-0737 requires each applicant or licensee to conduct a DCRDR on a schedule negotiated with the Nuclear Regulatory Commission (NRC).

NUREG-0700 describes four phases of the DCRDR and provides applicants and licensees with guidelines for its conduct.

The phases are:

1. Planning
2. Review
3. Assessment and implementation
4. Reporting

2. EVALUATION OF THE DCRDR

The NRC evaluation of the organization, process and results of the River Bend Station (RBS) has comprised the following, consistent with Section 18.1 and Appendix A to Section 18.1 of the Standard Review Plan (NUREG-0800, Ref. 3):

1. An evaluation (Ref. 4) of the DCRDR Program Plan submitted by the applicant (Ref. 5)

2. An on-site in-progress audit of the DCRDR conducted July 24-27, 1984 (Ref. 6)

3. An evaluation of the applicant's DCRDR Summary Report (Ref. 7)

4. A pre-implementation audit meeting with the applicant's DCRDR team leader and human factors contractor, January 23, 1985, and

5. Review of GSU letter (Ref. 8) dated January 23, 1985 providing supplemental information to clarify the applicant's Summary Report.

6. SER input on the River Bend Station Detailed Control Room Design Review (Ref. 10) dated March 20, 1985, which summarizes the staff's evaluation findings regarding the required elements of the RBS DCRDR.

The staff was assisted in Items 1-3 above by consultants from Lawrence Livermore National Laboratory (LLNL). Enclosed with the SER input was the Technical Evaluation Report (TER) prepared by LLNL (Ref. 9). Except as noted, the staff concurred with the evaluation, conclusions and recommendations contained in the LLNL report.

In the SER input, the staff concluded that GSU met the DCRDR requirements except for the incomplete items below:

1. GSU should confirm the continued participation of human factors specialists in the remaining DCRDR activities.

2. GSU should provide, for confirmatory review, the additional task analysis documentation discussed in the SER under Function and Task Analysis.

3. GSU should confirm that the remaining control room survey items have been completed and provide acceptable resolutions and implementation schedules for any significant HEDs identified.

4. GSU should respond to the specific concerns regarding resolution of the HEDs identified in Appendices A and B to the Technical evaluation report attached to the staff's SER.

5. GSU should confirm that all control room modifications resulting from the DCRDR have been verified to assure they have provided the expected correction and do not introduce new HEDs.

Items 1, 2, and 5 above are confirmatory items that required additional documentation to confirm what the staff believes to be acceptable accomplishments or commitments by the applicant. Items 3 and 4 were considered open items since the results of the applicant's efforts could not be predicted in advance. All five items are addressed by GSU in the DCRDR Summary Report Supplement dated May, 1985.

This report reviews the five incomplete items described in the applicants DCRDR Summary Report Supplement dated May, 1985.

3. DCRDR SER Incomplete Items

Item 1 GSU should confirm the continued participation of human factors specialists in the remaining DCRDR activities.

Section 6.2 of the Summary Report Supplement states that GSU letter RBG-19, 936 (Docket No. 50-458), dated January 23, 1985, clarifies the procedures used to resolve and implement HEDs. It is further stated that Section 6.2 provides additional information to confirm the continued participation of human factors specialist in the remaining DCRDR activities.

Section 6.2.1 of the applicant's Summary Report Supplement states that the results of the design research necessary to ensure that accurate improvements were being developed were reviewed by Mr. Robert J. Liddle of the consultant's human factors staff (General Physics Corporation). This review ensured that HED corrective actions were in compliance with human factors conventions prior to their implementation on the control boards. Discrepancies identified by Mr. Liddle were submitted to Gulf States Utilities (GSU) for action. Mr. Liddle continued to work with GSU as these discrepancies were resolved and corrective actions were implemented. We conclude that GSU will satisfy the intent of Item 1.

Item 2 GSU should provide, for confirmatory review, the additional task analysis documentation discussed in the SER under Function and Task Analysis.

The SER states that the applicant should provide written documentation for at least one emergency sequence which unequivocally demonstrates how it was determined that the inventoried displays and controls provided the necessary information and control capability. GSU selected the sequence "Inadequate Core Cooling" for this purpose.

Section 6.3,of the applicant's Summary Report Supplement, Task Analysis Documentation, contains the following additional task analysis documentation describing the selected emergency sequence.

- Appendix A - Task Analysis worksheets for sequence A, "Inadequate Core Cooling"
- Appendix B - Guidelines for Documentation of Instrumentation and Controls (instruction and criteria for instrumentation and controls tables, flow charts to verify equipment suitability, I&C Alpha listing).
- Appendix C - Examples of Instrumentation and Control Data Sheets
- Appendix D - Equipment characteristic forms (Equipment identification, Display characteristics, control states)
- Appendix E - Equipment Suitability form and associated HEDs (describing suitable equipment, and unsuitable equipment needing corrective action).

The text of the Summary Report Supplement describes the interrelationship of the above appendices to the following sections of the DCRDR Summary Report.

- o Section 1.2.4 - Verification of Task Performance Capabilities
- o Figure 1.2-9 - Flow Chart of Decision Process for Verifying Equipment Suitability.
- o Figure 1.2-8 - I and C Equipment Characteristics form (used in appendix D)
- o Section 1.2.3.7 - Control Room Inventory
- o Section 1.3 - Assessment and Implementation Phase.

The text of Section 6.3 describes the use of the referenced documents to systematically compare the information and control requirements identified on the task analysis worksheets (Appendix A) with the as-built instrumentation and controls present in the main control room, (Appendix C and Appendix D). The form illustrated in Appendix E was utilized as a worksheet in the process of the determination of equipment suitability.

The results of the comparison to determine equipment suitability and availability were recorded on the task analysis worksheets.

Discrepancies were written up as HEDs and assessed for corrective action by the process described in the DCRDR Summary Report. The Summary Report Supplement states that General Physics subject matter experts and human factors specialists conducted the verification of availability and suitability with the support of GSU startup engineering personnel and the GSU DCRDR team leader.

We have reviewed the additional documentation and conclude that GSU has satisfied the intent of Item 2.

Item 3 GSU should confirm that the remaining control room survey items have been completed and provide acceptable resolutions and implementation schedules for any significant HEDs identified.

The Summary Report Supplement states that the remaining control room survey items (e.g. lighting, noise levels communications, HVAC, availability of procedures, adequate protective clothing). were completed on May 2, 1985 by R. Liddle, D. Chase, and D. Looney, using the same methodology as was used on the original survey. The survey identified three additional HEDs (No. 875, 876, 877) which relate to labeling on the remote shutdown panels. These HEDs are included in Section 6.4, Control Room Survey Completion, of the Summary Report Supplement. Also included are completed versions of original survey HEDs (Section 7.5 of the Summary Report) which were left open pending panel completion (e.g. HEDs No. 199, 24, 108, 31, 20, 481, 94). We find that the resolution of all 10 of the above HEDs is satisfactory.

We conclude that GSU has satisfied Item 3.

Item 4 GSU should respond to the specific concerns regarding resolution of the HEDs identified in Appendices A and B to the Technical Evaluation Report attached to the staff's SER.

Section 6.5 of the Summary Report Supplement contains updated information for HEDs listed in the SER.

Appendices F and G of the Summary Report Supplement reflect the updated status of Appendices A and B of the Summary Report and any additional information requested in the DCRDR SER. Appendix H contains HEDs whose implementation schedule has changed since their submittal on the DCRDR Summary Report.

We have reviewed Section 6.5 and Appendices F, G, and H and conclude that:

A. The proposed implementation schedule of "prior to exceeding 5% power" is acceptable as described.

B. The updated resolutions of the HEDs in Appendices F, G, and H are acceptable with the exceptions noted in Appendices A and B of this report.

It is recommended that the applicant submit additional responses satisfactory to the NRC which address the comments in Appendices A and B of the report so that the NRC can determine whether Item 4 is satisfied.

Item 5 GSU should confirm that all control room modifications resulting from the DCRDR have been verified to assure they have provided the expected correction and do not introduce new HEDs.

Sections 6.2.2 and 6.6 of the Summary Report Supplement state the intent to satisfy this item. An on-going human factors maintenance plan (Section 1.3.5 of the Summary Report) is in place and is being implemented under an approved site procedure (PEP-0006).

Changes affecting the human factors design of the main control room, including those resulting from the DCRDR, have been or will be verified to assure that the desired correction has been obtained without introducing new HEDs. Mr. R. Liddle (General Physics Corporation) will participate in the review of corrective actions resulting from the DCRDR, and will assist GSU in the verification of completed corrective actions. No details are stated describing how GSU will inform the NRC of the status and completion of verification of presently open HED corrective actions before exceeding 5% power. It is recommended that GSU arrange with the NRC an acceptable and mutually agreeable advisory and check procedure which will ensure the completion in a manner satisfactory to the NRC of verification actions prior to exceeding 5% power.

4. Conclusions

Based on our review of the RBS Summary Report Supplement we conclude that GSU is conducting a RBS DCRDR that will meet the five remaining DCRDR requirements stated in the SER input on the RBS DCRDR dated March 20, 1985 (Ref. 10).

However, we note the following shortcomings in the Summary Report Supplement.

- o The Resolutions of certain HED's described in Appendices A and B of this report should be addressed and resolved to the satisfaction of the NRC.
- o The applicant and the NRC should arrange a mutually agreeable procedure to ensure that the NRC is advised of the progress and completion of verifications prior to exceeding 5% power.

5. REFERENCES

1. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," May 1980; Revision 1, August 1980.

2. NUREG-0737, "Clarification of TMI Action Plan Requirements, Supplement 1," December 1982.

3. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" Section 18.1, Rev. 0 and Appendix A to Section 18.1, Rev. 0, September 1984.

4. Letter from A. Schwencer, NRC, to W. Cahill, Jr., transmitting staff comments on River Bend Station Control Room Design Review Program Plan, April 25, 1984.

5. Letter from J.E. Booker, GSU, to H.R. Denton, submitting the River Bend Station Detailed Control Room Design Review Program Plan, January 31, 1984.

6. Letter from A. Schwencer, NRC to W. Cahill, Jr. transmitting the results of the In-Progress Audit of the River Bend Station Detailed Control Room Design Review, October 11, 1984.

7. Letter from J.E. Booker, GSU, to H.R. Denton, submitting the River Bend Station Detailed Design Review Summary Report, October 31, 1984.

8. Letter from J.E. Booker, GSU, to H.R. Denton, submitting additional information on the River Bend Station Detailed Control Room Design Review, January 23, 1985.

9. Technical Evaluation Report of the Detailed Control Room Design Review for Gulf States Utilities Company River Bend Station, prepared by Lawrence Livermore National Laboratory, January 29, 1985.

10. Memorandum for Thomas M. Novak from William T. Russell transmitting SER Input on the River Bend Station Detailed Control Room Design Review, March 20, 1985.

Appendix A

Unresolved HEDs from Summary Report Supplement Appendix F.

HED-196 - The response does not clearly address the HED. It is recommended that the response include:

- o A description of the power sources for all emergency lighting fixtures.
- o A discussion of whether there will be a need to operate with battery pack lighting only.

HED-432 - The response is not completely clear. It is recommended that the response clearly state:

- o Whether conventions were established.
- o A description of the conventions.
- o Whether the conventions will be consistently applied.

HED-77 - The response does not clearly describe how the recommendations will correct the discrepancy. It is recommended that the response clearly state:

- o A more complete description of the details of the demarcation and color coding.
- o An explanation of how the use of larger meters on P-680 will solve the problem of grouping (See HED-412).

HED-81 - It appears that a warning alarm will confirm but will not prevent an inadvertent operation. It is recommended that the response include an explanation of the rationale for not using warning labels or a guard to address the HED.

Appendix B

Unresolved HEDs from Summary Report Supplement Appendix G.

HED-228 - It appears that procedural action will correct this HED. It is recommended that the response commit to, and describe, such action and its implementation schedule.

HED-509,11 - It is recommended that the responses to these HEDs be coordinated. The color convention to be developed (See HED-509) should be described and a statement should be made that describes how it will be applied in the corrective actions selected for these HEDs.

HED-223 - An implementation schedule should be stated for this HED.

HED-319 - In our opinion the 18 foot separation between controls may be acceptable if two operators are on duty, but is not acceptable if only one operator is on duty. It is recommended that the response include a comment and statement addressing this opinion.

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SUPPLEMENTAL SAFETY EVALUATION REPORT
RIVER BEND STATION, UNIT #1
OPERATING AND MAINTENANCE PROCEDURES

SUBSECTION 13.5.2.2, OPERATING AND MAINTENANCE PROCEDURES PROGRAM

In Subsection 13.5.2.2 of NUREG-0989, Safety Evaluation Report (SER) Related to the Operation of River Bend Station, dated May 1984, the staff described the review and approval of the applicant's operating and maintenance procedures program through Amendment 11 of the Final Safety Analysis Report (FSAR). Letters from W. J. Cahill, Jr. to H. R. Denton, dated February 20, 1985 and June 21, 1985, transmitted Amendments 16 and 20 of the FSAR, which included changes made by the applicant to Chapter 13.5, Procedures, of the FSAR. The staff reviewed these changes and determined that the applicant's operating and maintenance procedures program continues to meet the relevant requirements of 10 CFR 50.34, and remains consistent with Regulatory Guide 1.33, ANSI N18.7-1976/ANS 3.2, and NUREG-0800, Standard Review Plan, Section 13.5.2, "Operating and Maintenance Procedures."

SUBSECTION 13.5.2.3, REANALYSIS OF TRANSIENTS AND ACCIDENTS; DEVELOPMENT OF EMERGENCY OPERATING PROCEDURES

Subsection 13.5.2.3, of the River Bend Station's (RBS) SER described the staff's review of the Procedures Generation Package (PGP) and identified one item (indicated as Confirmatory Item 60 in the SER) that had to be completed before the applicant's program for developing procedures could be approved. This item was the identification and justification of safety-significant differences between the RBS plant-specific technical guidelines and the NRC-approved BWR Owners Group technical guidelines. These differences and justifications were provided in a letter from J. E. Booker to H. R. Denton, dated January 15, 1985. Supplemental information was provided to the staff on February 11, 1985.

The staff's review consisted of evaluating the justification for each deviation from the generic technical guidelines using plant-specific procedures, supplemented with several telephone discussions with the applicant.

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The procedures submitted by the applicant have several plant-specific setpoints, operator action levels, and procedure references which are to be determined. During the routine pre-licensing inspection program and prior to fuel load, the staff will confirm that the information required to complete each procedure is incorporated into the procedure.

Justifications for several deviations included commitments by the applicant to change plant procedures based on, in most cases, improvements identified during the plant's procedure verification and validation effort. These procedure changes were identified in deviations discussed on pages 7, 10, 16, 17, 19, 20, 27, 35, 39, and 52 of Attachment 1 to the applicant's January 15, 1985 letter. In letters from J. E. Booker to H. R. Denton dated April 17, May 15, and July 15, 1985, the applicant satisfactorily identified and justified these changes to their plant procedures. The applicant is expected to incorporate the technical content of these letters in its emergency operating procedures (EOPs) and background documents in accordance with its EOP program. In addition, the applicant committed in its April 17, 1985 letter to change or clarify the deviations on pages 18, 34, and 50. The staff has confirmed the acceptability of these revised deviations.

The staff identified three errors associated with the deviations reviewed. First, although the justification on page 1 of Attachment 1 stated that generic EPG Cautions 1-8 were addressed in training and not contained in the procedures, two cautions which the operators would be expected to have difficulty remembering (6 and 8) are, in fact, included in the procedures. The applicant acknowledged this error and the staff found the exclusion of cautions 1-5 and 7 acceptable. Second, there is an inconsistency in the value used for the "maximum subcritical banked withdrawal position." The applicant stated that it had identified this inconsistency and that it had been corrected. The staff found this acceptable. Third, an apparent typographical error was identified in the justification for EOP-0002, step 3.4.4 (page 33 of the attachment) referencing 2 psig instead of 12 psig. An applicant representative stated that this error will be corrected. Based on this understanding, the staff found this acceptable.

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Finally, the RBS EOPs provide direction to the plant operators to vent the Primary Containment when containment pressure exceeds the "Primary Containment Pressure Limit" as defined by a curve of Primary Containment Water Level versus Suppression Chamber Pressure. The RBS proposed limit is based on an ultimate capacity of 56 psia which is in excess of the design pressure by a factor of about four. The NRC staff's Safety Evaluation Report on Revision 2 of the generic Emergency Procedure Guidelines (issued February 1983) has approved the use of twice design pressure as an interim limit provided containment integrity can be demonstrated. The staff is aware of a proposed revision to the generic EPGs which will result in a redefinition of the venting criteria. In this regard, it is our intent to continue the review of the proposed venting criterion (both generically and for each plant) which emphasis on the following areas:

1. Purge valve operability at the proposed venting pressure,

2. Consideration of depressurization rate during venting to limit suppression pool flashing,

3. Safety Relief Valve actuation at high containment pressures,

4. Structural analyses and tests, and

5. Limitation of offsite radioactive releases by selective use of vent paths.

Staff review of this item must be completed prior to operation above 5% power.

Based on this review, the staff concludes that Confirmatory Item No. (60) of the SER has been adequately addressed and, therefore, the applicant's program for developing EOPs is acceptable for fuel load and operation up to 5% rated power.

During the staff's review of the applicant's EOP program, it was determined that the applicant is considering changing their method of presenting EOPs currently described in their PGP from narrative to flow chart. It is the staff's position that a change in EOP presentation method from narrative to flow chart is quite a significant change and currently there are no acceptance criteria in NUREG-0800 (NRC Standard Review Plan, 13.5.2, Operating and Maintenance Procedures) which address the development of flow chart procedures. Furthermore, the applicant has not submitted a plan for developing flow chart EOPs. The staff should review the applicant's method for developing, verifying/validating and implementing flow chart EOPs prior to their implementation.

15.4.3 Operation of a Fuel Assembly in an Improper Position--Fuel Misloading Event

Two sorts of fuel misloading events may be considered: misorientation of a fuel assembly in its proper location and loading a fuel assembly into an improper location. The first of these events has trivial consequences for an S-lattice in the first cycle because the assembly fuel design is symmetric with respect to rotation. The slight tilt in the assembly caused by the misorientation has a negligible effect on the thermal-hydraulic performance of the fuel in the first cycle and tends to improve that performance in succeeding cycles.

The initial core consists of five bundle types with average enrichments in the high, low, and medium ranges with corresponding different gadolinium enrichments. The fuel bundle loading error consists of interchanging a bundle of one enrichment range with another bundle of a different enrichment range. The limiting fuel bundle loading error is that of interchanging a 2.78 percent enrichment bundle with a 0.94 percent enrichment bundle in the center of the core and away from a LPRM string. When the mirror image location (assumed to be instrumented) is placed on thermal limits the misloaded bundle will exceed operating limits.

The consequences of this event have been evaluated using the BWR simulator code which has been reviewed and approved by the staff. The results of the analysis show that a change in critical power ratio of 0.10 and a change in linear heat generation rate of 1.3 kW/ft occur for this event. These changes are well below the operating margin to fuel thermal limits. The staff concludes that the analysis of the fuel misloading event is acceptable.

The staff has evaluated the consequences of a spectrum of postulated fuel loading errors and concludes that the analyses provided by the applicant have shown for each case considered that either the error is detectable by the available instrumentation (and hence remediable) or the error is undetectable but the offsite consequences of any fuel rod failures are a small fraction of 10 CFR 100 guidelines.

The staff concludes that the applicant has met the requirements of GDC 13 with respect to providing adequate provisions to minimize the potential of a misloaded fuel assembly going undetected and has met 10 CFR 100 with respect to mitigating the consequences of reactor operations with a misloaded fuel assembly. These requirements have been met by providing acceptable procedures and design features that will minimize the likelihood of loading fuel in a location other than its designated place.

15.4.2 Rod Withdrawal Error at Power

Replace the paragraph (page 15-3 of the January 31, 1984 memo, "SER Input From River Bend Units 1 and 2") which begins: "It should be noted that this analysis is not applicable..." with the following: It should be noted that the statistical analysis described may not be applied to cores with a control cell core loading or those loaded to accommodate a high energy/high-discharge exposure cycle unless a compliance check is performed to demonstrate its applicability. Since the River Bend first cycle loading is a control-cell core the applicant has provided assurance that such a compliance check has been done (see letter dated June 19, 1985 to H. Denton, NRC from J. E. Booker, Gulf States). We therefore conclude that the withdrawal limits resulting from the generic analysis are acceptable for River Bend.