November 7, 2003

Mr. Paul D. Hinnenkamp
Vice President - Operations
Entergy Operations, Inc.
River Bend Station
P. O. Box 220
St. Francisville, LA 70775

SUBJECT: RIVER BEND STATION, UNIT 1 - ISSUANCE OF AMENDMENT RE: REMOVAL OF OPERATING MODE RESTRICTIONS FOR PERFORMING EMERGENCY DIESEL GENERATOR LOAD REJECT TESTING (TAC NO. MB8029)

Dear Mr. Hinnenkamp:

The Commission has issued the enclosed Amendment No. 137 to Facility Operating License No. NPF-47 for the River Bend Station, Unit 1. The amendment consists of changes to the Technical Specifications (TSs) in response to your application dated March 14, 2003, as supplemented by letter dated June 24, 2003.

The amendment revises TS 3.8.1, "AC Sources - Operating," Surveillance Requirements (SRs) pertaining to the testing of the Division 1 and 2 standby diesel generators (DGs). Specifically, the proposed changes eliminate mode restrictions that previously prevented performance of SRs during Modes 1 and 2 for the Division 1 and 2 DGs. The changes allow the performance of SR 3.8.1.9 and SR 3.8.1.10 for the Division 1 and 2 DGs during any plant operating mode.

A copy of our related Safety Evaluation is enclosed. The Notice of Issuance will be included in the Commission's next biweekly *Federal Register* notice.

Sincerely,

/RA/

Michael Webb, Project Manager, Section 1
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-458

Enclosures: 1. Amendment No. 137 to NPF-47
2. Safety Evaluation

cc w/encls: See next page

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ENTERGY GULF STATES, INC. **

AND

ENTERGY OPERATIONS, INC.

DOCKET NO. 50-458

RIVER BEND STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 137
License No. NPF-47

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Entergy Gulf States, Inc.* (the licensee) dated March 14, 2003, as supplemented by letter dated June 24, 2003, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this license amendment will not be inimical to the common defense and security or to the health and safety of the public; and

---

* Entergy Operations, Inc. is authorized to act as agent for Entergy Gulf States, Inc., and has exclusive responsibility and control over the physical construction, operation and maintenance of the facility.

**Entergy Gulf States, Inc., has merged with a wholly owned subsidiary of Entergy Corporation. Entergy Gulf States, Inc., was the surviving company in the merger.

E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and Paragraph 2.C.(2) of Facility Operating License No. NPF-47 is hereby amended to read as follows:

(2) <u>Technical Specifications and Environmental Protection Plan</u>

The Technical Specifications contained in Appendix A, as revised through Amendment No. 137 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. EOI shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. The license amendment is effective as of its date of issuance and shall be implemented within 30 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Robert A. Gramm, Chief, Section 1
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: November 7, 2003

ATTACHMENT TO LICENSE AMENDMENT NO. 137

FACILITY OPERATING LICENSE NO. NPF-47

DOCKET NO. 50-458

Replace the following page of the Appendix A Technical Specifications with the attached revised page. The revised page is identified by Amendment number and contains marginal lines indicating the areas of change.

Remove	Insert
3.8-8	3.8-8

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 137 TO

FACILITY OPERATING LICENSE NO. NPF-47

ENTERGY OPERATIONS, INC.

RIVER BEND STATION, UNIT 1

DOCKET NO. 50-458

1.0 INTRODUCTION

By application dated March 14, 2003, as supplemented by letter dated June 24, 2003, Entergy Operations, Inc. (the licensee), requested changes to the Technical Specifications (TSs) for the River Bend Station, Unit 1 (RBS). The supplemental letter dated June 24, 2003, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on April 15, 2003 (68 FR 18275).

The proposed changes would revise TS 3.8.1, "AC [Alternating Current] Sources - Operating," Surveillance Requirements (SRs) pertaining to testing of the Division 1 and 2 standby diesel generators (DGs). Specifically, the proposed changes will eliminate the specific mode restrictions for performance of SRs, which are currently prohibited during Modes 1 and 2, for the Division 1 and 2 DGs. This would allow the performance of SR 3.8.1.9 and SR 3.8.1.10 for the Division 1 and 2 DGs during any plant operating mode.

2.0 REGULATORY EVALUATION

This section identifies the structures, systems, and components (SSCs) related to the proposed license amendment and their associated regulatory requirements.

2.1 Description of SSCs

The proposed license amendment is related to the DGs and thus, this amendment would primarily affect the operation of the AC power system at RBS. A detailed description of the AC power system at RBS is provided in Chapter 8 of the RBS Updated Safety Analysis Report (USAR).

As described in the licensee's application dated March 14, 2003, RBS TS 3.8.1 specifies requirements for the electrical power distribution system AC sources. The Class 1E AC electrical power distribution system AC sources at RBS consists of the offsite power sources and the onsite standby power sources (i.e., DGs 1A, 1B, and 1C). As required by General Design Criterion (GDC)-17, "Electrical Power Systems," which is cited in Appendix A, "General

Design Criteria for Nuclear Power Plants," of the *Code of Federal Regulations* (CFR) Title 10, Part 50 (10 CFR Part 50), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the engineered safety feature (ESF) systems.

The Class 1E AC distribution system at RBS supplies electrical power to three divisional load groups with each division powered by an independent Class 1E 4.16 kilo Volts (kV) ESF bus. Each ESF bus has two separate and independent offsite sources of power. Each ESF bus also has a dedicated onsite DG. The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

Offsite power is supplied to the RBS switchyard from the transmission network. From the switchyard, two electrically and physically separated circuits provide AC power to each 4.16 kV ESF bus. The offsite AC electrical power sources are designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions.

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. A DG starts automatically upon receipt of a loss of coolant accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or on an ESF bus degraded voltage or undervoltage signal. In the event of a loss of the preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a design basis accident (DBA), such as a LOCA.

For Divisions 1 and 2, prior to automatically connecting the DG to the ESF bus (i.e., closing the DG output breaker), the breakers connecting the busses to the offsite sources are automatically opened and all bus loads, except ESF 480 Volt load center feeders, are tripped. The same signal that initiates the tripping of the offsite feeder breakers also causes all loads to be stripped from the 4.16 kV bus. Loads are automatically sequenced back onto the bus, following closure of the DG output breaker to the ESF bus, in a predetermined sequence in order to prevent overloading the standby emergency power source.

The safety function of the standby DGs is to ensure the availability of power to standby busses to mitigate DBAs and transients and maintain the unit in a safe shutdown condition. Each DG is provided with an overspeed trip to prevent damage to the engine. Recovery from the transient of a loss of a large load or full load reject could cause a DG engine overspeed, which, if excessive, might result in the trip of the engine. Full load reject may occur due to system faults or inadvertent breaker tripping. As a result, the RBS TSs have surveillances to demonstrate the capability of each DG to reject the largest load while maintaining a specified margin to the overspeed trip, and to demonstrate the capability to reject the full load (i.e., maximum expected accident load) on the DG without overspeed tripping or exceeding predetermined voltage limits.

Presently, SR 3.8.1.9 and SR 3.8.1.10 are required to be performed while the plant is shut down. However, credit can be taken for unplanned events that satisfy the SRs, including post-corrective actions that require performance of this surveillance to restore this component to an operable state. The restriction is enforced by a note preceding each of the SRs in the TS, which states, in part, that the surveillance shall not be performed in Modes 1 or 2. The TS Bases state that the reason for this restriction is to prevent unnecessary perturbations to the electrical distribution systems, which could challenge steady-state operation and thus, plant safety systems if the SR was performed with the reactor critical.

2.2 Applicable Regulations and Regulatory Guidance

GDC 17 requires, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of SSCs that are important to safety. The onsite system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. Electric power from the transmission network to the onsite electric distribution system is required to be supplied by two physically independent circuits that are designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. In addition, this criterion requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as a result of a loss of power from the unit, the offsite transmission network, or the onsite power supplies.

GDC 18, "Inspection and Testing of Electric Power Systems," requires that electric power systems that are important to safety be designed to permit appropriate periodic inspection and testing.

10 CFR 50.63, "Loss of All Alternating Current Power," requires that all nuclear power plants must have the capability to withstand a loss of all AC power for an established period of time.

10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" requires that preventive maintenance activities must not reduce the overall availability of the SSCs.

10 CFR 50.90, "Application for Amendment of License or Construction Permit," addresses the requirement for a licensee desiring to amend their license, which includes the TSs. The regulatory requirements related to the contents of TSs are set forth in 10 CFR 50.36, "Technical Specifications."

NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Chapter 16.1, "Risk-Informed Decisionmaking: Technical Specifications."

Regulatory Guide (RG) 1.9, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants." provides additional guidance for DG testing.

RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," describes a risk-informed approach, acceptable to the U.S. Nuclear Regulatory Commission (NRC or the Commission), for assessing the nature and impact of proposed licensing-basis changes by considering engineering issues and applying risk insights.

RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," describes an acceptable risk-informed approach specifically for assessing proposed TS changes. These RGs also provide acceptance guidelines for evaluating the results of such evaluations.

3.0 TECHNICAL EVALUATION

The staff has reviewed the licensee's analyses in support of its proposed license amendment, which are described in Section 4.0 of the licensee's submittal dated March 14, 2003, as supplemented by letter dated June 24, 2003. The staff evaluated the request based on findings of both deterministic and probabilistic assessments. The staff's evaluations are discussed in Sections 3.2 and 3.3. below.

3.1 Detailed Description of the Proposed Change

The proposed changes would affect SR 3.8.1.9 and SR 3.8.1.10. SR 3.8.1.9 requires that the single largest post-accident load on the DG be removed while the DG is operating in order to test its ability to prevent an overspeed condition. SR 3.8.1.10 requires that the DG output breaker be opened while the DG is carrying DBA loading in order to test its ability to maintain predetermined voltage parameters and to prevent an overspeed condition. Currently, these SRs contain a Note that precludes their performance during Modes 1 and 2 due to the assumption that they may cause electrical distribution system perturbations that could challenge steady-state operation and thus, plant safety systems.

For SR 3.8.1.9 and SR 3.8.1.10, the licensee proposes to revise the Notes to remove the mode restriction for all DGs. The proposed changes to SR 3.8.1.9 and SR 3.8.1.10 will allow performance of the testing during any mode of operation, including Modes 1 and 2.

3.2 Risk Assessment Evaluation

The staff reviewed the submittal using an approach based on RG 1.177 and NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Chapter 16.1, "Risk-Informed Decisionmaking: Technical Specifications." The staff first evaluated the licensee's probabilistic risk/safety assessment (PRA/PSA) and the impact of the change on plant operational risk, as expressed by the change in core damage frequency (ΔCDF) and the change in large early release frequency (ΔLERF). The change in risk is compared against the acceptance guidelines presented in RG 1.174. This evaluation also aims to ensure that plant risk does not increase unacceptably during the period when equipment is taken out of service (OOS) per the license amendment, as expressed by the incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP). The incremental risk is compared against the acceptance guidelines presented in RG 1.177.

The staff also addressed the need to preclude potentially high-risk plant configurations that could result if equipment, in addition to that associated with the proposed license amendment, are taken OOS simultaneously, or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved. The objective of this part of the review is to ensure that adequate programs and procedures are in place for identifying risk-significant plant configurations resulting from maintenance or other operational activities and taking appropriate measures to avoid such configurations.

3.2.1 Staff Technical Evaluation

In this section the staff evaluates the impact of the proposed TS changes on plant operational risk. The staff review involves three aspects: 1) evaluation of the validity of the PSA and its application to the proposed TS changes, 2) evaluation of the PSA results and insights stemming from its application, and 3) evaluation of the configuration risk management to ensure potentially high-risk plant configurations are avoided.

3.2.1.1 PSA Capability

To determine whether the PSA used in support of the proposed TS change is of sufficient quality, scope, and detail, the staff evaluated the relevant information provided by the licensee in their submittal and considered the findings of recent PSA reviews. The staff's review of the licensee's submittal focused on the capability of the licensee's PSA model to analyze the risks stemming from the proposed TS change and did not involve an in-depth review of the licensee's PSA.

For the quantitative evaluation of risk impacts of the proposed TS changes, the licensee used Revision 3A of the RBS PSA model. This model is an at-power Level I internal events risk model. An independent assessment of the RBS PSA, using the self-assessment process developed as part of the Boiling Water Reactor (BWR) Owners' Group PSA Peer Review Certification Program, was completed to ensure that the RBS PSA was comparable to other PSA programs in use throughout the industry. To this end, a PSA certification team completed an inspection and review of the RBS PSA in April 1998 and completed a PSA certification report in October 1998. The certification team found that the RBS PSA is fully capable of addressing issues, such as those associated with extending the DG allowed outage time (AOT), with a few enhancements. The RBS PSA has also benefitted from subsequent plant reviews of the other BWR-6 plants.

Additional information on the PSA certification review was provided to the staff as part of a license amendment request to extend the AOT for the Division 1 and Division 2 DGs from 72 hours to 14 days. The same version of the RBS PSA model was used in this license amendment request (i.e., Revision 3A). The safety evaluation, dated September 25, 2002, on the DG AOT extension license amendment request, states that the staff agreed with the peer review group's overall assessment and that the PSA was adequate for its application. Since the subject of the current license amendment request is likewise related to the Division 1 and Division 2 DGs, the staff finds that the PSA is adequate for this application as well.

Revision 3A of the RBS PSA model does not address the risks associated with external events, such as seismic events and internal fires, though these events were addressed in the licensee's individual plant examination (IPE) of external events (IPEEE). As described in the following subsection, the licensee performed qualitative evaluations to assess the risk impact of these non-modeled events due to the proposed TS change.

3.2.1.2 PSA Results and Insights

Although the TS Bases, as currently written, state that the reason for the restriction in the SRs is to preclude the potential for perturbations of the electrical distribution system during plant operation, the licensee reconsidered this basis and determined that the noted concern is unwarranted. The licensee based this conclusion on the RBS AC power supply and associated protection features, industry and plant experience with the performance of testing required per the affected SRs, administrative controls that minimize plant risks during performance of the affected testing, and the low probability of a significant voltage perturbation during such testing.

In the original submittal, the licensee stated that there was no historical data for the actual response of the Division 1 and Division 2 emergency busses during this testing. However, following the original submittal, as discussed in the supplemental letter dated June 24, 2003, the licensee did obtain the test data during Refueling Outage 11, in the spring of 2003, which confirmed their conclusions. That test data showed no significant transient during the full load reject test and no discernable voltage transient for the partial load reject test. The voltage step change was slight and no overshoot occurred, indicating that there is considerable margin above the degraded voltage setpoint. Based on the licensee's analyses and actual test data, the staff finds that the probability of a significant voltage perturbation during this testing is expected to be negligibly small.

In addition, the surveillance tests make the DG unavailable for responding to an accident during specific portions of the testing. The licensee states that the risk of performing the noted required surveillances during plant operation is not significantly greater than the risk associated with the performance of other DG surveillances required by the TSs that are not prohibited from being performed during plant operations. For example, SR 3.8.1.9 and SR 3.8.1.10 are performed by paralleling the DG in test with offsite power, which is similar to the existing monthly run of the DG that is performed with the plant on-line.

However, the proposed on-line surveillance tests do have the potential for increasing risk by making a DG unavailable to perform its safety function during certain portions of the testing. Much of the risk assessment information cited by the licensee was provided to the NRC previously as part of the emergency core cooling system (ECCS) surveillances for the DGs. The load reject tests associated with Division 1 and 2 DGs, performed per SR 3.8.1.9 and SR 3.8.1.10, are contained within the ECCS surveillances. It is only during certain portions of these surveillances that the DGs are not able to immediately respond to an accident. The licensee identified that the longest unavailability time for the Division 1 and Division 2 DGs was associated with ECCS tests STP-309-601 and STP-309-602, which was for 8 hours.

For the average maintenance model, the RBS base CDF is 3.39E-6/year. The licensee made conservative estimates of the equivalent yearly core damage probability (CDP) when a DG is assumed OOS for the whole year based on the risk achievement worth (RAW) for each of the DGs. This results in the following annual CDP estimates:

	CDP on Yearly Basis
Baseline	3.39 E-6
DG A OOS	8.14 E-6 (RAW=2.4)
DG B OOS	6.78 E-6 (RAW=2.0)
DG C OOS	6.10 E-6 (RAW=1.8)

The additional OOS time for each DG due to the proposed TS change is estimated to be 12 hours per cycle. On a yearly basis, this results in 8 hours for each DG, with the assumption of an 18-month cycle. Using the above information, the ΔCDF associated with the proposed testing-at-power change is estimated to be 9.91E-9/year. This value is significantly smaller than the RG 1.174 acceptance guideline of 1.0E-6/year for very small CDF increases. The accompanying ICCDP for the Division 1 DG, which bounds the impact from the other DGs, is calculated to be 6.5E-9. This value is also significantly less than the RG 1.177 acceptance guideline of 5.0E-7.

The licensee states that the calculation of ΔLERF and ICLERP are not necessary since these two parameters are a fraction of ΔCDF and ICCDP, respectively, and the calculated ΔCDF and ICCDP are both below the respective ΔLERF and ICLERP guideline values from RG1.174 and RG 1.177.

As stated in NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," the licensee's IPEEE was meant to be a vulnerability screening analysis rather than a full scope PSA. While PSA techniques were used to develop CDF values associated with internal fires, the licensee states that the IPEEE results are still those of screening analyses and thus, are not directly comparable to the CDF results from the IPE. The CDF values generated for the IPEEE, according to the licensee, are intended to show that the CDF is low enough that a vulnerability does not exist. The risk estimates of external events contains some substantial uncertainties. These uncertainties led the licensee, in many cases, to the application of conservative assumptions to bound the accident and demonstrate that no vulnerabilities existed.

By letter dated June 30, 1995, the licensee submitted their IPEEE for RBS. The licensee received the staff evaluation report (SER) by letter dated June 13, 2001, in which the staff concluded that the aspects of seismic events, fires, and high winds, floods, and other events were adequately addressed. The licensee has not updated the RBS IPEEE, but has qualitatively evaluated the IPEEE and its results specifically for this application, as described below.

RBS developed a fire PSA to address the fire portion of the IPEEE. The same PSA model was used as in the licensee's IPE submittal. The licensee's basic approach was to find a target set of equipment associated with a particular fire scenario. The licensee chose components that may be directly impacted by the fire scenario or may be impacted by fires affecting cables that power or control the components. Based upon the fire scenario, the licensee selected existing initiators from the plant full power internal events PSA to represent the type of plant shutdown that could occur. The list of initiating events and basic events representing the components lost were input as failures into the full power PSA model to derive conditional core damage probabilities (CCDPs) given a fire. The licensee typically multiplied the CCDP by the fire ignition frequency to derive an estimated CDF for a particular fire scenario.

In the Level 1 PSA model used for the IPEEE, there were 33 functional accident sequence groupings. Only 16 of these functional sequences applied to the fire PSA and only 5 functional sequences contributed more than 1% to any of the remaining fire areas. The top 5 functional sequences were:

TBU - Fire-induced loss-of-offsite power (LOOP) followed by a failure of DG 1A and 1B. High pressure core spray was assumed to fail due to a loss of standby service water return during a station blackout. Reactor core isolation cooling was assumed to fail due to a loss of flow and level instrumentation. These assumptions were conservatively made due to a lack of cable routing information for these components. Without any injection, core damage occurs.

TW - Transient followed by failure of all decay heat removal (DHR). High-pressure coolant makeup fails immediately, but the vessel is successfully depressurized and low-pressure makeup is initially successful. However, without DHR, containment failure due to overpressurization eventually occurs. Containment failure results in a harsh environment in the auxiliary building that causes failure of the safety/relief valves which repressurizes the vessel and fails the operating low-pressure systems.

TUV - Transient followed by a failure of all high-pressure and low-pressure coolant makeup. Power conversion is assumed to fail due to a lack of cable routing information. Without coolant makeup, core damage occurs.

TUX - Transient followed by a failure of high-pressure coolant makeup. Reactor depressurization fails, preventing the use of low-pressure coolant makeup systems. Power conversion is assumed to fail due to a lack of cable routing information. Without coolant makeup, core damage occurs.

S2UV- Transient with one stuck-open relief valve, followed by a failure of all high-pressure and low-pressure coolant makeup. Without coolant makeup, core damage occurs.

Because the DGs are only required to mitigate LOOP events in the PSA, the only fire scenarios affecting risk due to the proposed TS change are those that would lead to a LOOP event. The licensee states that random occurrences of LOOP events concurrent with internal fire events are considered probabilistically insignificant and were not considered further for this application. The staff agrees that random LOOP events coincident with an internal fire would be much less likely than the risk contribution from fires that directly induce LOOP events, and thus accepts the licensee's simplified approach to considering the fire-related impacts of the proposed TS change.

The individual fire areas identified by the licensee as important were reviewed for sequences contributing to the CDF to identify those that involve the fire-induced LOOP initiator. Two fire areas were identified: Fire Area C25 (main control room) and Fire Area T-2/Z-2 (turbine building general area elevation 67'-6").

For main control room (MCR) fires, it was assumed that a cabinet fire that was contained to a non-divisional cabinet would result in a LOOP and a loss of all non-divisional equipment. This assumption is conservative since the majority of non-divisional cabinets do not contain equipment related to offsite power and power distribution. Also, the licensee states that the Electric Power Research Institute fire events database shows that the electrical cabinet fires that have occurred at U.S. nuclear plants are generally benign. For MCR fires that result in evacuation, it is assumed that all offsite power is lost. The unavailability of a single DG then dominates the CCDP.

The CDF for the MCR non-evacuation fire scenarios involving non-divisional cabinets is calculated to be 1.62E-8/year. The CDF for the MCR non-evacuation fire scenarios involving divisional cabinets is calculated as 1.15E-6/year. Therefore, the total CDF for the MCR non-evacuation scenarios for all cabinets is 1.17E-6/year. The CDF for MCR fires that result in evacuation is 3.70E-6/year. Therefore, the licensee's value of the total CDF for MCR fires is 4.87E-6/year.

The northeast corner of Fire Area T-2/Z-2 has a horizontal run of cables (cable tray 1TC352N) that provides power to components fed by Reserve Station Service (RSS) #1 and resides about six inches away from motor control center (MCC) cabinets 1NHS-MCC1E and 1NHS-MCC1F. Additionally, cable tray 1TC350N, which provides power to components fed by RSS #2, intersects 1TC352N at a 90 degree angle in close proximity to the same cabinets. A cabinet fire would potentially damage both the Division 1 and Division 2 offsite power cables. This is conservatively assumed to result in a LOOP. The CDF for fire area T-2/Z-2 is 1.52E-6/year. This fire area is in the turbine building and does not contain any safe shutdown equipment. If a fire were to occur in this fire area while a DG were OOS, the remaining DGs would not be impacted.

Thus, the contribution of fire-induced LOOP scenarios to the overall fire CDF of 2.5E-5/year is 5.24E-6/year, or, approximately 21 percent. Taking a DG OOS for maintenance could impact these scenarios, but not in a way that is significantly different than a LOOP from the internal events PSA. Fire-induced LOOP sequences progress in a manner similar to a LOOP with failure of offsite power recovery. However, the fire risk values take no credit for the ability to connect DG 1C to the Division 1 bus. In fact, the fire PSA model gave little credit for recovery of offsite power, since it was assumed that the non-divisional power cables were damaged. Therefore, the staff finds that the proposed TS change will have a negligibly small impact on the fire-related risk contribution for RBS.

According to the RBS IPEEE, "RBS is classified in NUREG-1407 as a reduced scope plant of low seismicity. Thus, emphasis was placed on conducting detailed seismic walkdowns." Since RBS did not perform a seismic PSA analysis for the IPEEE, the seismic risk contribution has not been quantified. Maximum ground acceleration for both horizontal and vertical motion for the safe shutdown earthquake is 0.1g (RBS USAR Section 2.5.2.6), which was also used as the IPEEE review level earthquake due to the low seismicity of the site.

The main contributor to seismic risk related to this application is the potential for creating a LOOP event. Ceramic insulators for offsite power transformers tend to be the most vulnerable components in the offsite power system during a seismic event. NUREG/CR-4550, Volume 4, Revision 1, Part 3, "Analysis of Core Damage Frequency, Peach Bottom Unit 2 External Events," estimates the median peak ground acceleration at which these ceramic insulators are lost to be approximately 0.25g and other references cite a high confidence of a low probability of failure seismic capacity of 0.1g for the ceramic insulators. Based on this information and using the information available from NUREG-1488, "Revised Livermore Seismic Hazard Estimates for Sixty-Nine Nuclear Power Plant Sites East of the Rocky Mountains," the seismically-induced LOOP event at RBS has a frequency on the order of about 1E-5/year. This is considerably less than the random, non-seismic, frequency of a LOOP event. Considering the low seismicity of the RBS site and the typical seismic robustness of DGs and their support systems, the staff finds that the seismic risk contribution for RBS is negligibly small and does not impact the conclusions of this license application.

Considering the information provided in the licensee's submittal, the staff finds that there is reasonable confidence that the total CDF is not greater than 1E-4/reactor-year. Thus, the risks associated with the non-modeled events are not expected to impact the staff's conclusion regarding the acceptability of the proposed TS changes, especially in light of the qualitative evaluations performed by the licensee to address the potentially risk-sensitive fire areas.

3.2.2 Risk-Informed Configuration Risk Management

The preferred source of power to the ESF busses when the plant is on-line is from offsite power sources. When the DG output breaker is opened in accordance with SR 3.8.1.10, the offsite circuit will continue to supply power to the bus. The offsite network is considered an "infinite bus" and will not be affected by DG unloading. Since system loading, before and after the transient, is within the rating of all transformers, switchgear, and breakers, the staff agrees that the overall effect on the ESF busses should be minor.

Additionally, the licensee will take the following compensatory measures during testing/maintenance:

1. An administrative control that uses the protected division concept will be used. This control allows work only on one division at a time in order to prevent work from being performed inadvertently on the remaining divisions.

2. The required action B.2 of RBS TS 3.8.1 also forces the licensee to identify the operability of equipment that is redundant to the inoperable equipment, thereby reinforcing the protected division concept.

The staff finds that with these measures in place, two required divisions will still be available for plant shutdown, cooldown, or DBA mitigation while the third division is inoperable due to testing.

During surveillance testing, RBS allows only one DG at a time to be operated in parallel with offsite power. This configuration provides for sufficient independence of the onsite power sources from offsite power while still enabling testing to demonstrate DG operability. In this configuration, it is possible for only one DG to be affected by an unstable offsite power system. Even then, it may be possible for operator action to be taken to manually reset the affected lockout relay so that the DG can be restarted if it were to trip due to an offsite transient. Additionally, if this unlikely scenario occurred, plant safe-shutdown capability would still be assured with the two remaining DGs.

The RBS Plant Administrative Procedure, ADM-0096, "Risk Management Program Implementation and On-Line Maintenance Risk Assessment," provides procedural requirements to conduct a risk assessment for all maintenance activities while in Modes 1, 2, or 3. The purpose of this procedure is to ensure that a process is in place to assess the overall impact of maintenance on plant risk and to manage the risk associated with equipment unavailability. This program implements the requirements of 10 CFR 50.65.

3.2.3 Comparison Against Regulatory Guidelines

The staff has determined that the licensee's RBS PSA, as supplemented to qualitatively address external events, is acceptable for this application. The PSA risk evaluation results are consistent with the RG 1.177 and RG 1.174 acceptance guidelines, indicating an expected very small increase in risk due to the proposed TS changes.

3.2.4 Probablistic Conclusion

In summary, based on the considerations discussed above, the staff finds that the proposed TS changes to allow DG testing during Modes 1 and 2 per SRs 3.8.1.9 and 3.8.1.10 are acceptable based upon the licensee's risk-informed assessment. This assessment concludes that the increase in plant risk is very small and consistent with the acceptance guidelines of RG 1.177 and RG 1.174.

3.3 Deterministic Evaluation

Although the licensee has demonstrated, based on a PSA basis, that performing on-line surveillance testing at power would result in no significant increase in risk, the staff also reviewed the amendment request from a deterministic approach as discussed below.

Currently, SR 3.8.1.9 and SR 3.8.1.10 can not be performed in Modes 1 and 2 due to RBS TS restrictions based on electrical distribution perturbation concerns. In the original submittal dated March 14, 2003, the licensee indicated that these SRs had been performed on Division 1 and Division 2 DGs in the past to return a DG to operability at power and these SRs created a non-excessive disturbance to the electrical distribution system, but that there was no historical data for the actual response of the Division 1 and 2 emergency busses during the testing. Since RBS did not have historical data for the actual response of the Division 1 and Division 2 emergency busses during this testing, the licensee committed to obtaining the bus voltage response data during the next scheduled performance of these surveillances during the next refueling outage (RFO11). As discussed in the supplemental letter dated June 24, 2003, the licensee obtained the test data during RFO 11, in the spring of 2003, which confirmed their conclusions. That test data showed no significant transient during the full load reject test and no discernable voltage transient for the partial load reject test. The voltage step change was slight and no overshoot occurred, indicating that there is considerable margin above the degraded voltage setpoint.

Because there was no data for Division 1 and 2 at the time of the original submittal, the licensee reviewed historical test data for the Division 3 DG full load reject tests performed with the unit off-line with the standby bus voltage monitored as the distribution system configurations are similar, with the Division 3 DG being somewhat smaller in capacity than the Division 1 and 2 DGs. The licensee stated that historical data on the above load rejection tests performed on the Division 3 DG, during plant shutdown, shows less than a 1.5 percent drop in ESF bus voltage with no apparent overshoot.

To support the Division 3 data, the licensee utilized an Electrical Transient Analysis Program (ETAP) Power Station simulation of the load reject test under off-line conditions to approximate Division 3 results and confirm the expected results of Divisions 1 and 2. The licensee states that for on-line conditions, the ETAP simulation was performed using worst case anticipated grid voltage (0.989 P.U.) under double contingency grid conditions for each DG. This included LOCA loading on the ESF busses for conservatism. The results demonstrated considerable margin between the final bus voltage and the degraded voltage relay setpoint. Based on the above discussion, the staff concludes that even if a significant low voltage transient occurred, the duration would be far too short to pick up the degraded voltage relay that requires nearly one minute to activate under degraded conditions.

The preferred source of power to the ESF busses when the plant is on-line is from offsite power sources. When the DG output breaker is opened in accordance with SR 3.8.1.10, the offsite circuit will continue to supply power to the bus. The offsite network is considered an "infinite bus" and will not be affected by DG unloading. Since system loading, before and after the transient, is within the rating of all transformers, switchgear, and breakers, the staff agrees that the overall effect on the ESF busses should be minor.

Additionally, the licensee will take the following compensatory measures during testing/ maintenance. The licensee will apply an administrative control that uses the protected division concept. This control only allows work on one division at a time in order to prevent work from being performed inadvertently on the remaining divisions. The required action B.2 of RBS TS 3.8.1 also forces the licensee to identify the operability of equipment that is redundant to the inoperable equipment, thereby reenforcing the protected division concept. The staff finds that with these measures in place, two required divisions will still be available for plant shutdown, cooldown, or DBA, while the third division is inoperable due to testing.

During surveillance testing, RBS allows only one DG at a time to be operated in parallel with offsite power. This configuration provides for sufficient independence of the onsite power sources from offsite power while still enabling testing to demonstrate DG operability. In this configuration, it is possible for only one DG to be affected by an unstable offsite power system. Even then, it may be possible for operator action to be taken to manually reset the affected lockout relay so that the DG can be restarted if it were to trip due to an offsite transient. Additionally, if this unlikely scenario occurred, plant safe-shutdown capability would still be assured with the two remaining DGs.

The RBS Plant Administrative Procedure, ADM-0096, "Risk Management Program Implementation and On-Line Maintenance Risk Assessment," provides procedural requirements to conduct risk assessment for all maintenance activities while in Modes 1, 2, or 3. The purpose of this procedure is to ensure that a process is in place to assess the overall impact of maintenance on plant risk and to manage the risk associated with equipment unavailability. This program implements the requirements of 10 CFR 50.65(a)(4) Maintenance Rule that uses a risk evaluation tool to assess the potential risk implications of planned or emergent work activities. This tool warns Planning and Scheduling/Outage personnel that plant risk goals are being approached or would be exceeded if work was allowed to be performed. These administrative controls contained in the above procedure minimize any potential to allow work on redundant DGs.

3.3.1 Deterministic Conclusion

The staff concludes that the licensee has demonstrated that the performance of the SRs during power operation would cause minimal perturbation on the electrical distribution system. Computer modeling supports this by providing results consistent with plant data for various modes of operation. Administrative controls and the paralleling of one DG at a time to the offsite network ensure remaining ESF division operability is not inadvertently jeopardized and ensures adequate ESF capability remains to shutdown the plant or mitigate DBAs. For these reasons the staff considers the proposed TS changes to be acceptable. The staff also concludes that the proposed changes to the RBS TSs will continue to satisfy requirements of GDC 17 and GDC 18.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Louisiana State official was notified of the proposed issuance of the amendment. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (68 FR 18275). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

6.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

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