September 5, 2002

Mr. William A. Eaton
Vice President, Operations GGNS
Entergy Operations, Inc.
P. O. Box 756
Port Gibson, MS 39150

SUBJECT: GRAND GULF NUCLEAR STATION, ISSUANCE OF AMENDMENT RE: REMOVAL OF OPERATING MODE RESTRICTIONS FOR PERFORMING EMERGENCY DIESEL GENERATOR TESTING (TAC NO. MB3487)

Dear Mr. Eaton:

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 153 to Facility Operating License No. NPF-29 for the Grand Gulf Nuclear Station, Unit 1 (GGNS). This amendment consists of changes to the Technical Specifications (TSs) in response to your application dated November 15, 2001, as supplemented by letters dated March 1 and June 19, 2002.

This amendment revises the GGNS TS Surveillance Requirements (SRs) pertaining to testing of the standby emergency diesel generators (DGs) to allow DG testing during reactor operation. The change removes the restriction associated with these SRs that prohibits conducting the required testing of the DGs during reactor operating Modes 1, 2, or 3.

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

Sincerely,

/RA/

David Jaffe, Senior Project Manager, Section 1
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-416

Enclosures: 1. Amendment No. 153 to NPF-29
2. Safety Evaluation

cc w/encls: See next page

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OFFICE	PDIV-1/PM	PDIV-1/LA	SPSB/SC(A)	EEIB/SC*	OGC	PDVI-1/SC
NAME	DJaffe	DJohnson	DGH for Mark Rubin**	CHolden	RWeisman** (nlo w/comment)	RGramm
DATE	9/4/02	9/3/02	08/20/02	7/23/02	08/30/02	9/5/02

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ENTERGY OPERATIONS, INC.

SYSTEM ENERGY RESOURCES, INC.

SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION

ENTERGY MISSISSIPPI, INC.

DOCKET NO. 50-416

GRAND GULF NUCLEAR STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 153
License No. NPF-29

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

   A. The application for amendment filed by Entergy Operations, Inc. (the licensee) dated November 15, 2001, as supplemented by letters dated March 1 and June 19, 2002, complied 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, 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 amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   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-29 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 153, are hereby incorporated into this license. Entergy Operations, Inc. 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 60 days of 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: September 5, 2002

ATTACHMENT TO LICENSE AMENDMENT NO. 153

FACILITY OPERATING LICENSE NO. NPF-29

DOCKET NO. 50-416

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
3.8-7	3.8-7
3.8-8	3.8-8
3.8-11	3.8-11
3.8-14	3.8-14

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 153 TO FACILITY OPERATING LICENSE NO. NPF-29

ENTERGY OPERATIONS, INC., ET AL.

GRAND GULF NUCLEAR STATION, UNIT 1

DOCKET NO. 50-416

1.0 INTRODUCTION

By application dated November 15, 2001, as supplemented by letters dated March 1 and June 19, 2002 (References 7.1 through 7.3, respectively), Entergy Operations Inc., et al. (EOI, Entergy, or the licensee), submitted a request for changes to the Grand Gulf Nuclear Station, Unit 1 (GGNS), Technical Specifications (TSs.) References 7.2 and 7.3 provided clarifying information that did not change 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 December 26, 2001 (66 FR 66464).

The proposed amendment would revise the GGNS TS Surveillance Requirements (SRs) pertaining to testing of the standby emergency diesel generators (DGs) to allow DG testing during reactor operation. The proposed changes would remove the restriction associated with SRs 3.8.1.9, 3.8.1.10, 3.8.1.13, and 3.8.1.17 that prohibit performing the required testing during Modes 1, 2, or 3.

2.0 REGULATORY EVALUATION

The staff finds that the licensee, in Section 3 of Attachment 1 to Reference 7.1, identified the applicable regulatory requirements. The regulatory requirements which the staff applied in its review of the application included: Title 10 of the *Code of Federal Regulations* (10 CFR), Part 2, Section 2.101; 10 CFR 50.59; 10 CFR Part 50, Appendix A, General Design Criteria (GDC)-17; 10 CFR Part 50, Appendix A, GDC-18; 10 CFR 50.90 for changes to TSs; and 10 CFR 50.92 for no significant hazard consideration.

3.0 TECHNICAL EVALUATION

The U.S. Nuclear Regulatory Commission (NRC or the Commission) staff has reviewed the licensee's regulatory and technical analyses in support of its proposed license amendment, described in Section 3 of Attachment 1 to Reference 7.1. The detailed evaluation below will support the conclusion 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 amendment will not be inimical to the common defense and security or to the health and safety of the public.

3.1 Deterministic Evaluation

3.1.1 SR 3.8.1.9 and SR 3.8.1.10

For performance of the load rejection tests specified in SRs 3.8.1.9 and 3.8.1.10, the typical approach taken is to load the DG under the test to the required load (via offsite power) and then open the DG output breaker. An alternate method for performing SR 3.8.1.9 is to trip the associated largest single load. At the present time, SR 3.8.1.9 and SR 3.8.1.10 cannot be performed in Modes 1 and 2 due to TS restrictions. Opening of the DG output breaker separates the DG from its associated emergency bus and allows the offsite circuit to continue to supply the bus. This evolution has little impact on plant loads. The power system loading during such testing is within the rating of all transformers, switchgear, and breakers, both before and after the load rejection, and, as further explained below, performance of the load rejection SRs does not cause any significant perturbations to the electrical distribution systems when the DG being tested is separated from the bus.

Reference 7.1 states that an analysis of bus voltage traces taken from previous SR tests has shown that the voltage drop that occurs during the test, is such that voltage during the “transient” remains well above the minimum required voltage for plant loads, and typically recovers well within 2 seconds. The licensee concluded, therefore, that the voltage “transient” experienced by loads on the affected bus is minor. These tests were conducted during plant shutdowns.

The staff was concerned that since the proposed testing will be performed during power operation when the expected voltage will be lower than during shutdown conditions, the testing as proposed could cause more perturbation in the electrical distribution system. Accordingly, the staff requested the licensee to explain how the perturbation during power operation is comparable to the previous test results. The staff also requested the licensee to demonstrate that the voltage drop on the safety bus after load rejection is well above the set points of degraded and loss of voltage relays.

In Reference 7.3, the licensee stated that during power operation, expected voltage at the Engineered Safety Features (ESF) 4.16 kilovolt (kV) buses, where the sensors monitor for voltage degradation/loss, is nearly equal to or only slightly more than the nominal value. One reason for this is that, according to Reference 7.4, Updated Final Safety Analysis Report (UFSAR), Section 8.2.4, Operating Limits, the nominal operating voltage at the 500 kV bus is 510 kV. Another reason is the relatively low loading factor of the station service transformers. The UFSAR minimum anticipated 500 kV source voltage (Reference 7.4) is 496 kV. According to the licensee, these operating conditions provide a sufficient margin between the available bus voltage and the degraded voltage trip setpoint settings, which are nominally 90 percent for Division I/II, and nominally approximately 88.5 percent for Division III, on a 4.16 kV base. The expected decrease for bus voltage as a result of performing the load rejection test is less than a 2 percent reduction on the respective ESF bus. Thus, even with the test performed at the UFSAR minimum anticipated 500 kV grid conditions, the expected bus voltage would remain above the degraded voltage set points.

Similarly, the time delay features for the degraded/loss of voltage schemes will ensure that the very brief transient will have settled out well before these timers would allow an actuation due to any transient effects. The minimum time delay for degraded voltage for Division I/II is

9 seconds, and for Division III is 4 seconds. The transient lasts significantly less than 2 seconds. The loss-of-voltage sensors have set points, nominally in the 70 percent bus voltage range, which are well below the degraded voltage sensors. The expected drop in bus voltage due to the proposed test will still maintain the available voltage significantly above these settings.

Based on the above discussion and past performance of this test, the staff concludes that conducting this test at power (Modes 1 and 2) will not cause significant perturbation to the electrical distribution system; therefore, the performance of these SRs during power operation is acceptable.

3.1.2 SR 3.8.1.13

The test for SR 3.8.1.13 is the verification that each DG's automatic trips are bypassed on an actual or simulated ECCS initiation signal except engine overspeed, generator differential current, and low lube oil pressure for DG 11 and DG 12. At the present time, SR 3.8.1.13 cannot be performed in Modes 1, 2, and 3 due to TS restrictions. Reference 7.1 states that performance to verify that non-emergency automatic trips are bypassed and that emergency automatic trips will trip the DG in an emergency, while at power, does not cause any perturbation on the safety bus because (1) this SR is not performed with the DG paralleled to offsite power, and (2) unavailability of the DG during the conduct of this test is minimal. DG unavailability mainly occurs when the DG is tripped in response to the emergency trips and then verified to be tripped prior to resetting the trips. Manual action is required to reset the emergency trips so that the DG can then be available to start in an actual emergency situation. Since the test is conducted with the DG unloaded and isolated from its respective emergency bus, there is no impact on the electrical distribution system. Therefore, there is no mechanism for challenging continued steady state operation.

The test is also performed by verifying that the non-emergency automatic trips do not trip the DG (i.e., the associated lockout relay is not tripped). The only jumpers and signal simulation required is executed at the relay level in the DG control circuitry such that only the associated DG is affected during this surveillance.

Based on the above, the staff concludes that since the test is conducted with the DG unloaded and isolated from its respective emergency bus, performance of this SR during power operation will not pose any threat to the safety of the plant. Therefore, the proposed change is acceptable.

3.1.3 SR 3.8.1.17

This test is typically performed in conjunction with the load rejection tests (while the DG is paralleled with the offsite source) by simulating a loss-of-coolant accident signal to the DG start circuitry, which causes the DG output breaker to open, as the DG is returned to a ready-to-load condition. At the present time, SR 3.8.1.17 cannot be performed in Modes 1, 2, and 3 due to TS restrictions. The performance of the test mode override test in accordance with this SR ensures that the availability of the DG under accident conditions is unaffected during the performance of the surveillance test. Similar to the tests performed for SRs 3.8.1.9 and 3.8.1.10, opening the DG output breaker separates the DG from its associated emergency bus and allows the offsite circuit to continue to supply the bus. Consequently, performing the testing required by SR 3.8.1.17 also does not cause any significant perturbation to the electrical distribution systems. The expected drop in bus voltage due to the proposed test will still maintain the available voltage significantly above degraded grid relay settings.

Based on the above, the staff concludes that the performance of SR 3.8.1.17 during power operation will not cause significant disturbance in the electrical system, or pose any threat to the safety of the plant operation. Therefore, the proposed change is acceptable.

3.1.4 Other Compensatory Measures/Restrictions

The licensee's approach to perform maintenance uses a protected division concept. This means that, without special consideration, it only allows work on one division at a time. This administrative control provides additional assurance that only one division at a time is worked on and it helps eliminate inadvertent work on the other division.

In addition, the GGNS procedures contain precautions to minimize risk associated with surveillance testing, maintenance activities, and degraded grid conditions, when paralleling a DG with offiste power. For example, during testing, only one DG is operated in parallel with offsite power at a time. 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 if this unlikely scenario were to occur, plant safe shutdown capability would still be assured with the two remaining DGs.

GGNS TSs impose restrictions on the amount of equipment allowed out of service at any given time. Required Action B.2 of TS 3.8.1, "AC Sources - Operating," requires identification of inoperable required features that are redundant to required features supported by the inoperable DG. This required action is applicable throughout the entire period of diesel inoperability. Inoperable features on the redundant division can then cause entry into other more severe required actions, thus providing further incentive not to make another DG inoperable. Additionally, the licensee's Safety Function Determination Program, TS 5.5.10, requires protection against loss of safety function.

Additionally, GGNS Plant Administrative Procedure 01-S-18-6 (Reference 7.5) provides procedures for conducting risk assessments for all maintenance performed while in Modes 1, 2, or 3. The purpose of Reference 7.5 is to ensure that a process is in place to assess the overall impact on plant risk associated with equipment unavailability, and to manage such risk. This program implements the requirements of the Maintenance Rule, 10 CFR 50.65(a)(4). This program uses an Equipment-Out-Of-Service risk evaluation tool to assess the potential risk implications of planned or emerging work activities, warning Planning and Scheduling/Outage personnel that plant risk goals are being approached or would be exceeded if work were allowed to be performed. The administrative controls contained in Reference 7.5 minimize any possibility of allowing work on redundant DGs. The risk evaluation tool contains a comprehensive model of important GGNS equipment and allows the licensee to evaluate the adverse effects of other maintenance activities and their impacts on DG maintenance. The administrative controls contained in Reference 7.5 minimize any potential to allow work on redundant DGs.

3.1.5 Conclusion-Deterministic Evaluation

The staff concludes that the licensee has provided sufficient assurance that performing SRs 3.8.1.9, 3.8.1.10, 3.8.1.13, and 3.8.1.17 while at power will not create a transient that could disrupt power operation and challenge the safety systems. The staff also concludes that the proposed changes do not affect GGNS's compliance with the requirements of GDC-17 and GDC-18. Therefore, the proposed changes are acceptable from a deterministic view point.

3.2 Probabilistic Risk Evaluation

The following sections provide the probabilistic safety assessment (PSA or PRA) insights.

3.2.1 Internal Events

3.2.1.1 Tier 1

During certain portions of the surveillance, the DG would not be able to immediately respond to an accident. DG unavailability during the performance of the proposed on-line DG testing is summarized in Attachment 4 of Reference 7.1 with the longest unavailability time of 8 hours. For the 8-hour DG test proposal at power, the licensee computed the annualized change in (Delta) Core Damage Frequency (CDF) for GGNS to be 3.81 E-8/r-yr, which is very small according to the guidelines of Regulatory Guide (RG) 1.174 (Reference 7.6). The annualized Delta Large Early Release Frequency (LERF), which is a fraction of the annualized Delta CDF, would also be very small according to the guidelines of RG 1.174 (less than 1.0 E-7/r-yr).

The licensee computed the Incremental Conditional Core Damage Probability (ICCDP) to be 3.22 E-8, which is significantly smaller than the RG 1.177 (Reference 7.7) guideline of 5.0 E-7, indicating a very small quantitative impact. The Incremental Conditional Large Early Release Probability (ICLERP) is a fraction of the ICCDP, and is, therefore, small when compared to the Reference 7.7 guideline of 5.0 E-8.

The above values of Delta CDF, ICCDP, and inferences of the acceptably small values of Delta LERF and ICLERP are reasonable and acceptable to the staff. There is also an unquantified risk reduction when the SR testing is not performed during the plant shutdown.

3.2.1.2 Tier 2

GGNS procedures contain precautions to minimize risk associated with surveillance testing, maintenance activities, and degraded grid conditions, when paralleling a DG with offsite power. For example, during testing, only one DG is operated in parallel with offsite power at a time. 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 power source 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 this unlikely scenario were to occur, safe plant shutdown capability would still be assured with the two remaining DGs.

3.2.1.3 Tier 3: On-Line Risk Management

As stated in Section 3.1.4 above, Reference 7.5 provides procedures for conducting risk assessment for all maintenance performed while in Modes 1, 2, or 3. This accounts for assessment of the overall impact on plant risk, management of the risk associated with equipment unavailability, and implementation of the requirements of the Maintenance Rule, 10 CFR 50.65(a)(4). This would minimize any possibility of allowing work on redundant DGs and also would minimize the adverse effects of other maintenance activities and their impacts on DG maintenance.

3.2.1.4 PSA Quality

The original GGNS Individual Plant Examination (IPE) was developed by the licensee with the assistance of Science Applications International Corporation and was submitted to the staff in 1992. It was revised in 1997, renamed, and issued as Reference 7.8, which used the results from PRA Model "GGNS PSA, Revision 1." An independent assessment of Reference 7.8 has been completed to ensure that it was comparable to other PSAs in use throughout the industry. This assessment applied the Self-Assessment Process developed as part of the Boiling Water Reactor Owners' Group (BWROG) PSA Peer Review Certification Program. The PSA Certification Team, which was a group of industry and utility experts selected by the BWROG, completed an inspection and review of the GGNS PSA in August 1997 and completed a PSA Peer Review certification report in October 1997 (Reference 7.9). The models and methodology used in Reference 7.8 were included in the PSA peer review certification. The quality of the PSA and completeness of the PSA documentation were also assessed. The Certification Team found that Reference 7.8 is fully capable of addressing issues requiring risk significance determination with a few enhancements.

Because the proposed changes to the TS for on-line DG testing have only a small impact on total DG unavailability, according to the licensee, any enhancements made to the GGNS PSA are not expected to significantly impact the overall conclusions of the above evaluations. For the same reasons, the staff has made the same conclusion.

3.2.2 External Events

By Reference 7.1, the licensee submitted its IPE for External Events (IPEEE) for GGNS (Reference 7.10). In Reference 7.10, fire was addressed using "Fire PRA" methods developed and described later in Reference 7.11 (GGNS was the pilot plant for the Electric Power Research Institute (EPRI) Guide), seismic impact was addressed using a "seismic margins" methodology, and other events were addressed by conforming to NUREG-0800 (Reference 7.12). EOI received the staff Safety Evaluation for the IPEEE by letter dated March 16, 2001, in which the staff concluded that the seismic, fires, high winds, floods and other events were adequately addressed. Of the events considered, seismic and fire are the initiators with the most potential for an induced loss-of-offsite power (LOOP). LOOP is relevant to the proposed changes because of the potential increase in DG unavailability. The following paragraphs provide the detailed discussion of the external events evaluated by the staff.

3.2.2.1 Seismic

GGNS was classified in NUREG-1407 (Reference 7.13), as a reduced scope plant of low seismicity; emphasis was placed on conducting seismic inspections for the IPEEE. Thus, the licensee did not make a direct determination of the LOOP due to seismic events as an initiator frequency, but estimated it as follows:

> ...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 [Reference 7.14]..., estimates the median peak ground acceleration at which these ceramic insulators are lost to be approximately 0.25 g. NUREG-1488 [Reference 7.15]..., provides an estimate for annual probability of exceedance for peak ground acceleration of approximately 2E-5 for GGNS and a ground acceleration of 0.25 g....

The licensee thus estimates the seismic LOOP initiator frequency as 2.3E-3/yr (3.9E-2/yr x 6E-2, where 3.9E-2 is the GGNS LOOP initiating event frequency and 6E-2 is the four-hour non-recovery probability of offsite power). Even if the likelihood of non-recovery of offsite power were somewhat greater given a seismic event, the seismic LOOP contribution would still be bounded by the normal LOOP scenario.

Based on this estimate and the relatively slight changes to the internal events PSA model, the licensee concludes that the impact of the proposed changes to seismic risk is very small. For the same reasons, the staff has made the same conclusion.

3.2.2.2 Fire

While the licensee uses PSA techniques to develop CDFs associated with internal fires, the IPEEE results are the results of screening analyses and therefore are not directly comparable to the CDF results from the internal event's PSA. The CDF values generated for the IPEEE were intended to show that the CDF is low enough that the vulnerability does not exist. The licensee did not develop the Fire PSA to the same level of detail as the internal events PSA. Therefore, the Fire CDF reported in the IPEEE should not be combined with, or directly compared with the internal events analysis. A review of the Fire PSA scenarios indicates that approximately 14.6 percent of the Fire CDF (1.3 E-6/r-yr) is associated with a fire-induced LOOP event. This compares with a 42.5 percent contribution (2.3 E-6/r-yr) from LOOP initiators for the base internal events PSA. These frequencies are relatively close, and since additional DG out-of-service time would primarily impact LOOP scenarios, the effect of the proposed change on Fire CDF would be expected to be similar to the impact on the corresponding internal events PSA CDF.

The staff concludes that, since the impact of the proposed change (8-hour at-power DG test time) on internal events risk is significantly within the RG guidelines, there is no need for a quantitative evaluation of the impact on fire risk, which should also be within the RG guidelines.

3.2.2.3 High Winds and Tornados

Reference 7.10 states that all safety-related structures, other than the Standby Service Water (SSW) system components, are protected against high winds, tornado wind loads, and tornado-generated missiles. The guidance in Reference 7.13 states that if a plant meets the Reference 7.12 criteria, high winds and tornados can be screened out as significant contributors to total CDF. The licensee made use of fairly recent tornado data for 10 years (1985 thru 1994). For the SSW components, a frequency assessment of tornado-generated missiles was performed. The licensee estimated this frequency to be 7.7E-9/r-yr. This frequency is substantially lower than the Reference 7.13 criterion of 1.0 E-6/r-yr.

The staff concludes that the risk due to high winds and tornado-generated missiles is acceptable, conforming to the Reference 7.13 guidelines.

3.2.2.4 Conclusions - External Events

Based on discussion in Sections 3.2.2.1 through 3.2.2.3 above, the staff concludes that the external events results were reasonable, considering the design and operation of the plant. The staff thus concludes that the aspects of seismic events, fires, and high winds and tornados (including missiles) were adequately addressed, and other external events were not of substantial consequence.

3.2.3 Conclusion - Probabilistic Risk Evaluation

The staff has reviewed the proposed amendment to remove the mode restriction to perform SRs 3.8.1.9, 3.8.1.10, 3.8.1.13, and 3.8.1.17 from a PRA perspective, and concludes that the available risk insights and findings support the proposed change.

The staff also concludes that the impact on plant risk of allowing the GGNS DGs to undergo 8-hour testing at power is very small for both internal and external events. The staff thus finds the proposed 8-hour DG testing at-power acceptable.

3.3 TS Changes

The licensee proposed to revise the TSs to reflect the deletion of mode restrictions for SRs pertaining to testing of the DGs to allow the SR testing during reactor operation. The changes remove the restrictions in SRs 3.8.1.9, 3.8.1.10, 3.8.1.13, and 3.8.1.17 that prohibit conducting the required testing of the DGs during reactor operating Modes 1, 2, or 3.

Based on the evaluations discussed in Sections 3.1 and 3.2 of this safety evaluation, the staff concludes that the above-described changes to the TSs are acceptable.

4.0 STATE CONSULTATION

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

5.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes surveillance requirements. The NRC staff has determined that the amendment involves 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 (66 FR 66464 published December 26, 2001). 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 amendment will not be inimical to the common defense and security or to the health and safety of the public.

7.0 REFERENCES

7.1 GNRO-2001/00083, William A. Eaton (Entergy) letter to NRC, "Grand Gulf Nuclear Station Proposed Amendment of Facility Operating License to Remove Operating Mode Restrictions for Performing Emergency Diesel Generator Testing," dated November 15, 2001.

7.2 GNRO-2002/00020, William A. Eaton (Entergy) letter to NRC, "Supplemental Information for License Amendment Request Removal of Operating MODE Restrictions for Performing Emergency Diesel Generator Testing," dated March 1, 2002.

7.3 GNRO-2002/00032, William A. Eaton (Entergy) letter to NRC, "Supplemental Information for License Amendment Request Removal of Operating MODE Restrictions for Performing Emergency Diesel Generator Testing," dated June 19, 2002.

7.4 Updated Final Safety Analysis Report (UFSAR), Section 8.2.4, "Operating Limits."

7.5 GGNS Plant Administrative Procedure No. 01-S-18-6, "Risk Assessment of Maintenance Activities."

7.6 U. S. Nuclear Regulatory Commission, Regulatory Guide 1.174, "An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," July 1998.

7.7 U.S. Nuclear Regulatory Commission, Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," August 1998.

7.8 Entergy Operations Inc., Grand Gulf Nuclear Station Engineering Report No. GGNS-97-0014, “GGNS PRA Update Summary and Results Report,” Revision 0, July 30, 1997.

7.9 Engineering and Research, Inc. Report No. C1029701-3130/3, “Grand Gulf PSA Peer Review Certification Report,” October 30, 1997.

7.10 GGNS Individual Plant Examination for External Events (IPEEE), November 1997.

7.11 Electric Power Research Institute, Technical Report 105928, “Fire PRA Implementation Guide,” December 1995.

7.12 NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants,” 1975.

7.13 NUREG-1407, “Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities,” June 1991.

7.14 NUREG/CR-4550, Vol. 4, Revision 1, Part 3, “Analysis of Core Damage Frequency, Peach Bottom Unit 2, Internal Events,” February 1999.

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