July 16, 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, UNIT 1 - ISSUANCE OF AMENDMENT RE: EXTENDED ALLOWED OUTAGE TIME FOR DIESEL GENERATORS (TAC NO. MB3973)

Dear Mr. Eaton:

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 151 to Facility Operating License No. NPF-29 for the Grand Gulf Nuclear Station, Unit 1. This amendment revises the Technical Specifications (TSs) in response to your application dated January 31, 2002, as supplemented by letter dated June 20, 2002.

The amendment revises TS 3.8.1, “AC Sources-Operating,” to extend the allowed outage time for a Division 1 or Division 2 diesel generator from the current 72 hours to 14 days.

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

Sincerely,

/RA/

David H. Jaffe, Sr. 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. 151 to NPF-29
2. Safety Evaluation

cc w/encls: See next page

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Accession No.: ML021860203 *Memo dated 06/28/02

OFFICE	PDIV-1/PM	PDIV-1/LA	EEIB/SC	OGC**	PDIV-1/SC
NAME	DJaffe	DJohnson concur electronically	CHolden*	AHodgen nlo w/changes	WReckley for RGramm
DATE	7/5/02	07/03/02	06/28/02	7/12/02	7/16/02

OFFICIAL RECORD COPY

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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. 151
License No. NPF-29

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

   A. The application for amendment by Entergy Operations, Inc. (the licensee) dated January 31, 2002, supplemented by letter dated June 20, 2002, 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, 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. 151, 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. This license amendment is effective as of its date of issuance and shall be implemented within 60 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA by William Reckley for/

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: July 16, 2002

ATTACHMENT TO LICENSE AMENDMENT NO. 151

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
3.8-1*	3.8-1*
3.8-2	3.8-2
3.8-3	3.8-3

* There are no changes on this page but it has been provided for clarity.

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 151 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 letter dated January 31, 2002, as supplemented by letter dated June 20, 2002, Entergy Operations, Inc., et al. (Entergy, EOI, or the licensee) submitted a request for changes to the Grand Gulf Nuclear Station, Unit 1 (GGNS), Technical Specifications (TSs). The June 20, 2002, supplemental letter provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the NRC staff's original proposed no significant hazards consideration determination as published in the *Federal Register* notice on April 2, 2002 (67 FR 15623).

The proposed changes would revise TS 3.8.1, "AC [alternating current] Sources-Operating," to extend the allowed outage time (AOT) for a Division 1 or Division 2 diesel generator (DG) from the current 72 hours to 14 days.

2.0 REGULATORY EVALUATION

General Design Criterion (GDC) 17, "Electric Power Systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to Title 10, Part 50, of the Code of Federal Regulations (CFR) requires, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of structures, systems, and components that are important safety. The onsite system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. The offsite power 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, GDC-17 requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as a result of 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. Pursuant to 10 CFR 50.36, "Technical specifications," a licensee's TS must establish limiting conditions for operation (LCO), which include AOT for equipment that is required for safe operation of the facility. In addition, 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," requires that preventive maintenance activities not reduce the overall availability of the systems, structures, and components. Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," provides guidance with respect to operating restrictions (i.e., AOTs) if the number of available AC sources is less than that required by the TS LCO. In particular, this guide prescribes a maximum AOT of 72 hours for an inoperable AC source.

The offsite and onsite power systems at GGNS are designed to comply with the requirements of GDC-17 and GDC-18. As described by the licensee's amendment request dated January 31, 2002, the GGNS Class 1E AC electrical power distribution system consists of three offsite power sources (two 500 kilo Volt (kV) sources and one 115 kV source) and three onsite standby power sources (DGs). The design of the electrical power system provides independence and redundancy to ensure an available power source of power to the engineered safety feature (ESF) systems. The Class 1E AC distribution system supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E ESF bus. 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 switchyard from the transmission network. From the switchyard, three electrically and physically separate circuits provide AC power to each 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 ESF bus is a dedicated DG. The DG starts automatically on a loss-of-coolant accident (LOCA) signal (i.e., low water level signal or high drywell pressure signal) or an ESF bus degraded voltage or undervoltage signal. In the event of a loss of 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 LOCA. The onsite AC emergency power system has the required redundancy; meets the single-failure criterion; is testable; and has the capacity, capability, and reliability to supply power to all required safety loads.

The Nuclear Regulatory Commission (NRC) staff finds that the licensee, in Sections 4.2.6 and 5.1 of its January 31, 2002, submittal, identified the applicable regulatory requirements. The regulatory requirements on which the NRC staff based its acceptance are GDC-17 and GDC-18 (and implementing guidance), and the applicable probabilistic review criteria.

3.0 TECHNICAL EVALUATION

The NRC staff has reviewed the licensee's regulatory and technical analyses in support of its proposed license amendment which are described in the licensee's submittal. The detailed evaluation below supports 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

Currently LCO 3.8.1, ACTION B.4, requires that, if an DG is inoperable, the inoperable DG must be restored to operable status within 72 hours. In addition, ACTIONS A.2 and B.4 establish a six-day limit on the maximum time allowed for any combination of required AC sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1. If either of these conditions is not met, the plant must be placed in Hot Shutdown within 12 hours and Cold Shutdown within 36 hours. An exception is allowed for the Division 3 DG. The licensee has proposed to extend the AOT for an inoperable DG from the current 72 hours to 14 days. The proposed extension is requested for Division 1 and Division 2 DGs only. This 11-day extension would also be applicable to the maximum time allowed for any combination of required AC sources to be inoperable during any single contiguous occurrence of failing to meet the LCO, to be commensurate with the extended DG completion time. Specifically, the completion time for ACTIONS A.2 and B.4 of "6 days from discovery of failure to meet LCO" would be revised to "17 days from discovery of failure to meet LCO" to accommodate the longer 14-day AOT.

The licensee stated that the proposed change would provide needed flexibility for the performance of corrective and preventive maintenance during power operation, and would reduce the risk of unscheduled plant shutdowns. In addition, the licensee stated that it intends to use the proposed 14-day AOT to perform planned maintenance or inspections at a frequency of no more than once per DG per operating cycle for each Division 1 and Division 2 DG. Beyond that, the licensee will continue to monitor and evaluate additional DG unavailability in accordance with the goals of 10 CFR 50.65 (the Maintenance Rule) to ensure that DG outage times do not degrade operational safety over time. The NRC staff finds the proposed changes to be acceptable for the reasons discussed in the following sections.

3.1.1 Station Blackout

The NRC staff evaluated the licensee's request to extend the AOT to determine whether it would erode the decrease in severe accident risk that was achieved by implementing the station blackout (SBO) requirements in 10 CFR 50.63, "Loss of all alternating current power."
GGNS is classified as a four-hour coping plant with 0.95 DG reliability. The licensee stated that the proposed change will not erode the decrease in severe accident risk that was achieved by implementing the SBO Rule, and that the extended DG AOT will not impact the SBO coping analysis. The assumptions used in the SBO analysis regarding reliability of the DGs will be unaffected by the proposed change since the licensee will continue to perform preventive maintenance and testing to maintain the reliability assumptions. Further, the results of the SBO analysis will be unaffected by the proposed change.

3.1.2 Diesel Generator Availability Due to On line Maintenance

The NRC staff evaluated the proposed change to ensure that the overall availability of the DGs will not be significantly reduced as a result of increased on-line preventive maintenance activities, and that the 14-day AOT will be consistent with the objectives and intent of the Maintenance Rule. The licensee stated that DG reliability and availability are monitored and periodically evaluated to ensure that DG extended AOTs do not degrade operational safety over time in accordance with the Maintenance Rule. The GGNS availability goal is 97.5 percent (no more than 2.5 percent unavailability). The unavailability for Division 1 DG was 0.89 percent for the year 2000 and 1.37 percent for 2001. The unavailability for the Division 2 DG was 0.66 percent for the year 2000 and 0.67 percent for 2001. This indicates that the overall unavailability of the DGs due to maintenance is reasonably controlled.

The Maintenance Rule performance goal for reliability is no more than one maintenance preventable functional failure (MPFF) per division in a rolling 18-month period. The licensee has reported that there were no MPFF for either Division in 2000 but there were two MPFFs for the Division 1 DG and one MPFF for the Division 2 DG in 2001.

3.1.3 Alternate Alternate Current Source

The licensee stated that the Division 3 High Pressure Core Spray (HPCS) DG at GGNS can be cross-connected to either Division 1 or Division 2 buses to provide an alternate AC source in the event of an SBO. The Division 3 DG has a continuous rating of 3300 kilo Watts (kW) and a 2000 hour rating of 3474 kW. The cross-connection is established by defeating the HPCS LOCA automatic initiation signals, defeating the particular load shed and sequencing panel for the division to be cross tied, defeating certain interlocks and performing breaker line-ups to load the Division 3 DG with desired loads. The licensee stated that cross-connection will be procedurally controlled by Off-Normal Event Procedure 05-1-02-1-4. This cross-connection can be accomplished within two hours. The procedure contains a table of loads which can be connected without exceeding the Division 3 DG capacity.

In addition, the licensee stated that in the SBO analysis the HPCS system is not relied upon as an injection source to the reactor vessel during an SBO. The reactor coolant system inventory control during the initial phases of an SBO will be provided by the Reactor Core Isolation Cooling (RCIC) system. After the four hour coping period, the decay heat removal utilizing one train of residual heat removal (RHR) will likely be necessary. Operators may use RHR shutdown cooling to remove decay heat from the reactor or use suppression pool cooling to cool the suppression pool. The Division 3 DG has enough capacity to supply power to one RHR pump needed for the RHR system to provide decay heat removal for the postulated scenario. Thus, in the event of a loss of offsite power (LOOP) and failure of the operable DG during the extended AOT, power can be supplied from the Division 3 DG to the Division 1 or Division 2 ESF buses for all of the needed loads for an SBO or LOOP.

3.1.4 Additional Operational Restrictions

The current TS requirements establish controls to ensure that, in the event a DG is inoperable, the redundant required features that depend on the operable DG as a source of power are verified operable. This provides assurance that a LOOP event will not result in a complete loss of safety function of critical systems during the period for which one of the DGs is inoperable.

Further, since the extension of the DG AOT is founded on the findings of both deterministic and probabilistic safety analyses, entry into this action requires the licensee to perform a risk assessment in accordance with the Configuration Risk Management Program (CRMP). This ensures that a proceduralized, probabilistic risk assessment (PRA)-informed process is in place to assess the overall impact of maintenance on plant risk before entering the LCO Action statement for planned activities.

3.1.5 Deterministic Conclusion

The NRC staff has evaluated the proposed changes to determine whether the applicable regulations continue to be met and concludes that extending the AOT for an inoperable Division 1 or Division 2 DG from the current 72 hours to 14 days is acceptable. The NRC staff's conclusion is founded on the following five considerations:

1. The extended AOT will be typically used to perform infrequent (i.e., once every 18 months) DG manufacturer's recommended inspections and preventive maintenance activities.

2. The extended AOT would reduce entries into the LCO and reduce the number of DG starts for major DG maintenance activities.

3. The Division 3 DG will be available and capable of powering either Division 1 or Division 2 loads in the event of an SBO or LOOP.

4. The licensee will implement its CRMP during the extended outage.

5. The RCIC will be available during the extended outage.

Further, the NRC staff believes that regulatory commitments, described in Section 3.4, herein, to implement other restrictions and compensatory measures would ensure the availability of the remaining sources of AC power during the extended AOT. The NRC staff also concludes that the proposed changes will not affect the compliance of GGNS with the requirements of GDC-17 and GDC-18.

3.2 PROBABILISTIC SAFETY ASSESSMENT INSIGHTS

To assess the overall impact on plant safety of the proposed 14-day AOT for Division 1 and Division 2 DGs, a probabilistic safety assessment (PSA) was performed consistent with the guidance pertaining to risk-informed criteria specified in RG 1.177, "An Approach for Plant-Specific Risk Informed Decisionmaking: Technical Specifications." The changes in average Core Damage Frequency (CDF) and average Large Early Release Frequency (LERF), as well as the Incremental Conditional Core Damage Probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP) resulting from the 14-day AOT were evaluated. This evaluation included consideration of the Maintenance Rule Program established pursuant to 10 CFR 50.65(a)(4) to control performance of other potentially high-risk tasks during a DG outage and consideration of specific compensatory measures to minimize risk. All of these elements were included in a risk evaluation performed using a three-tiered approach suggested in RG 1.177, as follows:

- Tier 1: PSA Capability and Insights,

- Tier 2: Avoidance of Risk-Significant Plant Configurations, and

- Tier 3: Risk-Informed Configuration Risk Management.

Evaluations per each of these tiers are provided by the licensee in this section.

3.2.1 TIER 1: PSA Capability and Insights

As previously noted, the licensee's risk-informed support for the proposed revision to the DG AOT (for either Division 1 or Division 2) is based on PSA calculations performed to quantify the changes in the average CDF and LERF and the values of the ICCDP and ICLERP, resulting from the increased AOT.

The licensee computed the results of a risk evaluation for a 14-day DG AOT and compared them with the guidelines of RG 1.174, "An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," for changes in the annual average CDF and LERF, and of RG 1.177 for ICCDP and ICLERP. The ICCDP and ICLERP evaluations were based on the Division 1 DG (DG A), which provides the upper bound limiting values for these risk metrics. The licensee's values for the ICCDP and ICLERP illustrate that the proposed DG AOT change to 14 days has only a small quantitative impact on plant operating risk and result in an unquantified risk reduction due to non-maintenance at shutdown. The licensee's risk evaluation results are tabulated below:

Risk Metric	Guideline	GGNS Results
Delta CDF (average)	less than 1E-6/yr	2.73E-7/yr
ICCDP	less than 5E-7	2.15E-7
Delta LERF (average)	less than 1E-7/yr	1.04E-8/yr
ICLERP	less than 5E-8	8.32E-9

The above values of Delta CDF, ICCDP, Delta LERF, and ICLERP are reasonable and acceptable to the NRC staff. There is also an unquantified risk reduction due to avoidance of non-planned maintenance of the DGs at shutdown.

3.2.2 TIER 2: Avoidance of Risk-Significant Plant Configurations

The licensee has a CRMP in place at GGNS in order to comply with 10 CFR 50.65, particularly with respect to paragraph (a)(4). This program provides assurance that risk-significant plant equipment configurations are precluded or minimized when plant equipment is removed from service. When a plant DG is removed from service, risk increases posed by potential combinations of equipment out of service will be managed, according to the licensee, in accordance with the CRMP program. Additional contingencies, which the licensee states will be administratively controlled, include:

1. Weather conditions will be evaluated prior to entering an extended DG AOT for voluntary planned maintenance. An extended DG AOT will not be entered for voluntary planned maintenance purposes if official weather forecasts are predicting severe conditions (hurricane, tropical storm, tornado, or snow/ice storm) that could significantly threaten grid stability during the planned outage time.

2. The condition of the offsite power supply and switchyard will be evaluated prior to entering the extended AOT for planned maintenance.

3. No elective maintenance will be scheduled within the switchyard that would challenge offsite power availability during the proposed extended DG AOT.

4. Operating crews will be briefed on the DG work plan, with consideration given to key procedural actions that would be required in the event of a LOOP or SBO.

5. High pressure injection systems (HPCS [high-pressure core spray] and RCIC) will not be taken out of service for planned maintenance while DG A (Division 1) or DG B (Division 2) is out of service for extended maintenance.

Additionally, the licensee emphasizes that it has the capability and procedures for cross-connecting the HPCS DG to either the Division 1 or Division 2 ESF bus. This capability is included in the PSA models used for the risk assessment.

The licensee states that while in the proposed extended DG AOT, additional elective equipment maintenance or testing that requires the equipment to be removed from service will be evaluated and activities that yield unacceptable results will be avoided. Cutsets were generated for DG A and B out of service individually. The licensee reviewed these cutsets for insights as to which systems or actions are most critical to avoid plant risk while a DG is out of service for extended maintenance. The cutsets were also reviewed to identify a list of in-service equipment that would be more important as a result of DG A or DG B being out of service.

For DG A, the primary systems included:

Offsite Power Supply
Division 1 DC [direct current] power supply
Division 2 DC power supply
Reactor Core Isolation Cooling (RCIC)
DG B (Division 2)
DG C (Division 3)
High Pressure Core Spray (HPCS)
Division 3 SSW [standby service water]
Division 2 SSW

For DG B, the primary systems included:

Offsite Power Supply
Division 1 DC power supply
Division 2 DC power supply
Reactor Core Isolation Cooling (RCIC)
DG A (Division 1)
DG C (Division 3)
High Pressure Core Spray (HPCS)
Division 3 SSW
Division 1 SSW

The licensee states that procedural and TS controls that will ensure that these systems are not removed from service while a DG is out of service for extended maintenance are already in place. Most of these systems in an out-of-service condition would result in an Equipment Out of Service (EOOS) color code of "Red." The licensee states that it would not enter this level of risk voluntarily. A "Red" risk condition typically overlaps conditions prohibited by TSs or conditions requiring entry into a TS Action statement. Plant General Manager or Designee notification is required upon entering a "Red" condition from emergent activities. If an entry into a "Red" condition occurs (e.g., due to equipment failures), the licensee would take steps to restore any equipment out-of-service for testing or maintenance that could improve overall plant safety. The licensee would take timely actions to reduce plant risk by either restoring inoperable or unavailable equipment or putting the plant in a lower power or shutdown state, taking into account risk associated with the transient required to achieve the lower power state, which could affect this decision.

3.2.3 TIER 3: Risk-Informed Configuration Risk-Management

Consistent with the last paragraph of the Maintenance Rule (10 CFR 50.65 (a)(4)), and as indicated above, the licensee has developed a program that it states ensures that the risk impact of out-of-service equipment is appropriately evaluated prior to performing a maintenance activity. The licensee procedures that govern this process are GGNS administrative procedure 01-S-18-6, "Risk Assessment of Maintenance Activities," and the "GGNS Shutdown Operations Protection Plan." Procedure 01-S-18-6 ensures that the risk from planned maintenance is evaluated and that maintenance activities are scheduled appropriately. This program requires an integrated review (i.e., both probabilistic and deterministic) to identify risk-significant plant equipment outage configurations. This review is required both during the work management process and for emergent conditions during normal plant operation. Appropriate consideration is given to equipment unavailability, operational activities such as testing or load dispatching, and weather conditions. This licensee program includes provisions for performing a configuration-dependent assessment of the overall impact on plant risk of proposed plant configurations prior to and during the performance of maintenance activities that remove equipment from service. Risk is re-assessed if an equipment failure/malfunction or emergent condition produces a plant configuration that has not been previously assessed. For planned maintenance activities, the licensee performs a risk assessment of the proposed activities on plant safety prior to commencing the scheduled work. This assessment includes the following considerations:

- Maintenance activities that affect redundant and diverse structures, systems, and components (SSCs) that provide backup for the same function are minimized.

- The potential for planned activities to cause a plant transient are reviewed and work on SSCs that would be required to mitigate the transient is avoided.

- The licensee will not perform maintenance that is likely to exceed a TS or Technical Requirements Manual (i.e., a licensee controlled document containing requirements removed from the TS as part of a conversion to the Improved Standard TS) completion time requiring a plant shutdown.

- For Maintenance Rule Program High Risk Significant SSCs, the impact of the planned activity on the unavailability performance criteria is evaluated.

- As a final check, a quantitative risk assessment is performed to ensure that the activity does not pose any unacceptable risk. This evaluation is performed using the Level 1 PSA model.

Planning and Scheduling and Operations reviews emergent work to ensure that it does not invalidate the assumptions made during the schedule development process. Prior to starting any work, the proposed work scope and schedule are critically reviewed to assure that plant safety and operations are consistent with management expectations.

3.2.4 Fire Protection

The probability of plant fire events is not assessed for distinct plant activities such as DG maintenance. However, the licensee's Fire Protection Program attempts to minimize fire risk through various design features and administrative controls that address fire prevention, as well as mitigation. A description of the GGNS Fire Protection Program is provided in Appendix 9B of the GGNS Updated Final Safety Analysis Report. GGNS Administrative Procedure 01-S-10-1, "Fire Protection Plan," prescribes the fire prevention and fire protection policies necessary to implement the approved Fire Protection Program. The program assures that an adequate balance of the defense-in-depth concept is maintained to minimize both the probability and consequences of damage due to fire throughout the GGNS site.

The Fire Protection Program uses a three-tiered approach:

1. The application of administrative controls to prevent fires from starting.

2. The use of active engineering design features to detect and suppress fires, limiting damage consequences of fires that do start.

3. The use of passive barriers in combination with the design of plant safety systems such that fires will not prevent essential plant safety functions from achieving and maintaining safe shutdown.

Fire prevention is accomplished primarily through application of the following procedures:

- 10-S-03-4, Fire Protection: Control of Combustible Material, establishes requirements for the safe storage, transport, and use of combustibles in safety related areas and non-safety related areas of the plant.

- 10-S-03-3, Fire Prevention: Control of Ignition Sources, establishes controls for hot work and any other potential ignition sources within the plant.

- 10-S-03-8, Fire Watch Program–describes the responsibilities and duties of persons associated with assigning, documenting, and performing fire watch duties.

3.2.5 PSA Model Development,Quality

The licensee's plant PSA model was first developed for the Individual Plant Examination (IPE) that was submitted to the NRC staff by letter dated December 23, 1992 (GNRO-92/00157), in response to Generic Letter 88-20, "Individual Plant Examination for severe accident vulnerabilities." The NRC staff issued its Safety Evaluation Report (SER) for the IPE by letter dated March 7, 1996 (GNRI-96/00067), wherein the NRC staff concluded that the licensee's IPE submittal met the intent of Generic Letter 88-20, without identifying any major weaknesses. An independent assessment of the licensee's PSA to assure that it was comparable to those of other PSAs in use throughout the industry has been completed. This assessment applied the self-assessment process developed as part of the Boiling Water Reactor Owners' Group PSA Peer Review Certification Program. The PSA Certification Team completed an inspection and review of the licensee's PSA in August 1997 and completed a PSA Certification Report in November 1997. The models and methodology used in Revision 1 of the PSA were included in the PSA Certification review. The quality and completeness of the PSA documentation were also assessed. The certification team found that the PSA is fully capable of addressing issues such as those associated with extending the Division 1 and Division 2 DG AOTs from 72 hours to 14 days.

At the time of the DG AOT extension request, the licensee's PSA was undergoing its second major revision. Changes being made include operational and hardware changes, as well as some methodology changes that impact the evaluation of offsite AC power recovery. The licensee states that this revision (Revision 2) is still in progress, but that the present DG AOT extension request evaluation was performed using an interim model, which captures the important model changes developed through September 2001. The licensee will evaluate the risk metrics for the DG extended AOT using the updated risk model, when available, and provide a summary of the results to the NRC staff (see Commitment 7, Section 3.4, herein).

The licensee's Level 2 PSA model has not been revised since the original IPE submittal. An evaluation of the impact on LERF of the DG AOT extension was performed using the results of Sensitivity Case 1 of the IPE. This sensitivity more closely resembles the current version of the GGNS Emergency Procedures/Severe Accident Procedures, with regard to the venting of the vessel through the main steam isolation valves. Since the primary impact of the proposed AOT is on the CDF associated with loss of station power (LOSP) and SBO, the licensee estimates LERF based upon the fraction of large early releases associated with sequences initiated by a LOSP event.

3.2.6 External Events

By letter dated November 15, 1995, the licensee submitted its IPE for External Events (IPEEE) for GGNS. In the IPEEE, fire was addressed using fire PSA methods (i.e., Electrical Power Research Institute Topical Report TR-105928, "Fire PRA Implementation Guide"), seismic impact was addressed using a seismic margins methodology, and other events were addressed by conforming to the 1975 Standard Review Plan (SRP). The NRC staff's SER dated March 16, 2001, concluded that the aspects of seismic events, fires, and 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 LOOP. A LOOP is relevant to the proposed changes because of the potential increase in DG unavailability.

3.2.7 Seismic

GGNS was classified in NUREG-1407, “Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities, June 1991," as a reduced scope plant of low seismicity; emphasis was placed on conducting seismic walkdowns for the IPEEE. Thus, the licensee did not make a direct determination of the seismic LOOP 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, Vol. 4, Rev. 1, Part 3, “Analysis of Core Damage Frequency, Peach Bottom Atomic Power Station Unit 2,” estimates the median peak ground acceleration at which these ceramic insulators are lost to be approximately 0.25 g. NUREG-1488, “Revised Livermore Seismic Hazard Estimates for Sixty-Nine Nuclear Power Plants East of the Rocky Mountains,” 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/yrx6E-2, where 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 estimate, and the relatively minor changes to the internal events PSA model, the licensee states that the impact of the proposed changes to seismic risk is very small. The NRC staff finds this statement to be accurate.

3.2.8 Fire

While the licensee used PSA techniques to develop CDFs associated with internal fires, the IPEEE results are still screening analyses and, therefore, are not directly comparable to the CDF results from the internal events PSA. The CDF values generated for the IPEEE were intended to show that the CDF is low enough that a 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 (1.3E-6/r-yr) is associated with a fire-induced LOOP event. This compares with a 42.5 percent contribution (2.3E-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 (14-day at-power AOT) on internal events risk is well within the RG guidelines, and there is no need for a quantitative evaluation of the impact on fire risk, which should also be within the RG guidelines.

3.2.9 High Winds and Tornadoes

The licensee’s IPEEE submittal states that all safety-related structures, except the SSW system components, are protected against high winds, tornado wind loads, and tornado-generated missiles. The licensee states that the SSW system components are not protected against postulated tornado-generated missiles. The guidance in NUREG-1407 is that, if a plant meets the 1975 SRP criteria, high winds and tornados can be screened out as significant contributors to the total CDF. The licensee made use of fairly recent tornado data for 10 years (1985 through 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 NUREG-1407 criterion of 1.0E-6/r-yr. The NRC staff thus finds that the risk due to high winds and tornado-generated missiles is acceptable, conforming to NUREG-1407 guidelines.

The NRC staff concludes that the external events results were adequately complete and reasonable, considering the design and operation of the plant. The NRC staff thus concludes that the aspects of seismic events, fires, and high winds and tornadoes (including missiles) were adequately addressed, and other external events were not of substantial consequence.

3.2.10 PSA Conclusion

The NRC staff concludes that the impact on plant risk of allowing 14-day at-power AOT for GGNS Division 1 and Division 2 DGs is very small for both internal and external events.

3.3 CHANGES TO THE TECHNICAL SPECIFICATIONS

Currently LCO 3.8.1, REQUIRED ACTION/COMPLETION TIME B.4, requires that if a DG is inoperable, the inoperable DG must be restored to operable status within 72 hours (3 days). In addition, REQUIRED ACTION/COMPLETION TIME A.2 and B.4 establish a 6-day limit on the maximum time allowed for any combination of required AC sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1. The licensee has proposed extending the DG AOT from 3 days to 14 days, which is an increase of 11 days. Based upon the licensee meeting both deterministic and probabilistic criteria, the NRC staff concludes that extending the COMPLETION TIME for the DG AOT in REQUIRED ACTION B.4, from 3 to 14 days is acceptable. Likewise, the extension of the COMPLETION TIME for 6-day limit on the maximum time allowed for any combination of required AC sources, in REQUIRED ACTIONS A.2 and B.4 is acceptable. The licensee has also proposed a clarification to the COMPLETION TIME for REQUIRED ACTION B.4 to state that the 72 hour AOT for the Division 3 DG has not been changed. This clarification is acceptable.

3.4 REGULATORY COMMITMENTS

The licensee has committed to include the following provisions, limitations, and compensatory actions related to the extended AOT:

1. Weather conditions will be evaluated prior to entering an extended DG AOT for voluntary planned maintenance. An extended DG AOT will not be entered for voluntary planned maintenance purposes if official weather forecasts are predicting severe conditions (hurricane, tropical storm, tornado, or snow/ice storm) that could significantly threaten grid stability during the planned outage time.

2. The condition of the offsite power supply and switchyard will be evaluated prior to entering the extended maintenance period.

3. No elective maintenance will be scheduled within the switchyard that would challenge offsite power availability during the proposed extended DG AOT.

4. High-pressure injection systems (HPCS and RCIC) will not be taken out of service for planned maintenance while DG A (Division 1) or DG B (Division 2) is out of service for extended maintenance.

5. Operating crews will be briefed on the DG work plan whenever the extended AOT period is used, with consideration given to key procedural actions that would be required in the event of a LOOP or SBO.

6. Entergy intends to limit use of the extended AOT for voluntary planned maintenance or inspections to once within an operating cycle for each DG (Division 1 and Division 2).

The supplemental letter dated June 20, 2002, provided two new commitment as follows:

7. Entergy will evaluate the risk metrics for the DG extended AOT using the updated risk model, when available, and provide a summary of the results to the NRC staff.

8. The HPCS DG (Division [3]) will not be taken out of service for planned maintenance while EDG [Emergency DG] 11 (Division [1]) or EDG 12 (Division [2]) is out of service for extended maintenance.

The NRC staff finds that reasonable controls for the implementation and for subsequent evaluation of proposed changes pertaining to the above regulatory commitments are best provided by the licensee’s administrative processes, including its commitment management program. The above regulatory commitments do not warrant the creation of regulatory requirements.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Mississippi State official 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. 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 (67 FR 15623, published April 2, 2002). 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.

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