Entergy

Entergy Operations, Inc.
P. O. Box 756
Port Gibson, MS 39150
Tel 601 437 6409
Fax 601 437 2795

William A. Eaton
Vice President,
Operations
Grand Gulf Nuclear Station

GNRO-2002/00006

February 19, 2002

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

SUBJECT: License Amendment Request
Removal of Operating MODE Restrictions for
Performing High Pressure Core Spray Emergency
Diesel Generator Testing (LBDC-2002/003)
Grand Gulf Nuclear Station, Unit 1
Docket 50-416

REFERENCES: Letter from W. A. Eaton to USNRC, "Proposed Amendment of Facility Operating License to Remove MODE Restrictions for Performing Emergency Diesel Generator Testing" dated November 15, 2001.

Dear Sir or Madam:

Pursuant to 10CFR50.90, Entergy Operations, Inc. (Entergy) hereby requests the following amendment for Grand Gulf Nuclear Station, Unit 1 (GGNS). Entergy proposes to amend Technical Specification (TS) 3.8.1, "AC Sources – Operating" to remove the MODE restrictions for testing the High Pressure Core Spray (HPCS) Diesel Generator 13 (DG 13). The proposed change would remove the restriction associated with Surveillance Requirements (SR) that prohibits performing the required testing in MODES 1, 2, or 3. In conjunction with the letter referenced above this request will remove all current restrictions associated with testing of DG 13 during normal operations. The specific SR addressed in this submittal includes; SR 3.8.1.11, 3.8.1.12, 3.8.1.16, and 3.8.1.19.

The proposed change has been evaluated in accordance with 10CFR50.91(a)(1) using criteria in 10CFR50.92(c) and it has been determined that this change involves no significant hazards considerations. The bases for these determinations are included in the attached submittal.

This submittal contains no new commitments for Entergy.

Entergy requests approval of the proposed amendment by August 01, 2002 in order to allow for work planning prior to the fall refueling outage. Once approved, the amendment shall be implemented within 60 days. Although this request is neither exigent nor emergency, your prompt review is requested.

A001

If you have any questions or require additional information, please contact Lonnie F. Daughtery at extension (601) 437-2334.

I declare under penalty of perjury that the foregoing is true and correct. Executed February 19, 2002.

Sincerely,

William A Eaton

WAE/LFD

attachments:
1. Analysis of Proposed Technical Specification Change
2. Proposed Technical Specification Changes (mark-up)
3. Changes to TS Bases pages

cc: Mr. Ellis W. Merschoff
Regional Administrator
U. S. Nuclear Regulatory Commission
Region IV
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011-8064

Mr. S. P. Sekerak, NRR/DLPM (w/2)
U. S. Nuclear Regulatory Commission
ATTN: ADDRESSEE ONLY
Mail Stop 07D1
Washington DC 20555-001

Mr. T. L. Hoeg, GGNS Senior Resident
Mr. D. E. Levanway (Wise Carter)
Mr. L. J. Smith (Wise Carter)
Mr. N. S. Reynolds
Mr. H. L. Thomas

Attachment 1

GNRO-2002/00006

Analysis of Proposed Technical Specification Change

1.0 DESCRIPTION

This letter is a request to amend Operating License NPF-29 for Grand Gulf Nuclear Station, Unit 1 (GGNS).

The proposed change will revise Technical Specification (TS) 3.8.1, "AC Sources – Operating" in order to remove the remaining MODE restrictions for performance of Surveillance Requirements (SR) for the High Pressure Core Spray (HPCS) Diesel Generator 13 (DG 13). This would allow the performance of all SR for the DG 13 during any MODE of plant operation. This will allow greater flexibility in scheduling these SR and will allow the performance during non-outage times. Having a completely tested Emergency Core Cooling System available for the duration of a refueling outage will reduce the amount of system re-alignments and operator workload during an outage.

The next GGNS refueling outage is scheduled for the Fall of 2002. Entergy desires that this amendment be issued by August 1, 2002 to support work planning prior to the outage.

2.0 PROPOSED CHANGE

Currently TS 3.8.1 contains Notes, which restrict performance of certain SR during MODE 1, 2, or 3. In the referenced letter Entergy requested that SR 3.8.1.9, 3.8.1.10, 3.8.1.13 and 3.8.1.17 be changed to remove the Notes associated with these SR. The referenced submittal asked for those changes that were applicable to all three divisions of Diesel Generators. The proposed changes requested in this subsequent submittal are limited to DG 13.

Entergy proposes the following changes to TS 3.8.1:

a. Revise SR 3.8.1.11 to remove the MODE restriction from the Note for the Diesel Generator 13 only.

b. Revise SR 3.8.1.12 to remove the MODE restriction from the Note for the Diesel Generator 13 only.

c. Revise SR 3.8.1.16 to remove the MODE restriction from the Note for the Diesel Generator 13 only.

d. Revise SR 3.8.1.19 to remove the MODE restriction from the Note for the Diesel Generator 13 only.

The MODE restriction will remain applicable to Diesel Generator 11 (Division I) and Diesel Generator 12 (Division 2). The change will be affected by adding "not applicable to DG 13" to the current Note.

In summary, Entergy proposes to amend Technical Specification (TS) 3.8.1, "AC Sources – Operating" to remove the remaining MODE restrictions for testing the High Pressure Core Spray (HPCS) Diesel Generator 13 (DG 13). The basic TS change will remove the applicability of the current Note restricting performance of SR 3.8.1.11, 3.8.1.16, and 3.8.1.19 during MODES 1, 2, or 3 and SR 3.8.1.12 during MODES 1 or 2. The change will be affected by clarifying the current Note to make it not applicable to Diesel Generator 13.

Necessary changes will be made to the TS Bases in accordance with the Bases Control Program of TS 5.5.11. The proposed Bases changes are contained in attachment 3 and are for information purposes only.

3.0 BACKGROUND

Grand Gulf Nuclear Station (GGNS) Technical Specification (TS) 3.8.1, "AC Sources - Operating," specifies requirements for the Electrical Power Distribution System AC sources. The Class 1E AC Electrical Power Distribution System AC sources at GGNS consists of the offsite power sources and the onsite standby power sources, i.e., diesel generators (DGs) 11, 12, and 13. As required by 10 CFR 50, Appendix A, GDC 17, 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 GGNS supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 4.16 kV ESF bus. Each Engineer Safety Feature (ESF) bus is capable of being supplied by either of three 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 GGNS switchyard from the transmission network. Three electrically and physically separated circuits provide AC power to each of the 4.16 kV ESF buses. LCO 3.8.1 only requires two of the three offsite power sources to be OPERABLE. Currently only the two 500 kV sources are credited for meeting the LCO requirements. 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. A detailed description of the offsite power network and circuits to the onsite Class 1E ESF buses is found in Final Safety Analysis Report, (FSAR) Chapter 8, section 8.2 " Offsite Power System".

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus(es).

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 an ESF bus degraded voltage or undervoltage signal (refer to LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation"). In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DG in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident such as a LOCA. Transfer is accomplished by first opening the incoming offsite feeder breakers and subsequently closing the DG feeder breaker when the generator has reached rated speed and voltage. This arrangement lessens the likelihood that the offsite source (i.e., grid) and the onsite sources remain paralleled during periods of degraded grid conditions. A detailed description of the onsite power network is found in Final Safety Analysis Report, Chapter 8, section 8.3 " Onsite Power System".

For Divisions I and II, prior to auto connecting the DG to the ESF bus (i.e., closing DG output breaker), the breakers connecting the buses to the offsite sources are 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 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. Load shedding and sequencing for Divisions I and II is discussed in detail in the FSAR Section 8.3.1.1.3.

For Division III (High Pressure Core Spray - HPCS) loads are not shed and thus are not required to be sequenced back onto the bus. However, the design of the HPCS system ensures that the offsite and onsite source will not continue to operate in a parallel mode following receipt of either a LOCA or LOP signal. When in parallel operation the occurrence of a LOCA signal will cause, the HPCS DG output breaker to trip open. It will not be automatically closed unless the preferred offsite source of power is lost similar to the Division I and II designs. Following the receipt of a LOP signal, the offsite feeder breakers will trip open and the HPCS DG output breaker will automatically close.

The HPCS is designed and constructed to allow all active components to be tested during normal plant operations. The system has a full-flow test line to either the suppression pool or the condensate water storage tank (FSAR, Section 6.3.2.2.1) which allows testing without injecting into the reactor vessel. These features, along with the design of the electrical distribution system, allow Entergy to make this request to remove the remaining restrictions from testing the HPCS DG.

By virtue of this request and those contained in the referenced letter the HPCS DG and the HPCS System can almost be completely tested during normal plant operations. This on-line testing will minimize system manipulations and reduce operator workload during refueling outages. Having completed this testing during normal operations will eliminate approximately 36 hours of Operator intensive testing during an outage.

The Technical Specifications SR 3.8.1.11, 3.8.1.16, and 3.8.1.19 contain a Note preceding each of the SR, which state, in part, that the surveillance shall not be performed in MODES 1, 2, or 3. The TS Bases for these SR state, in part, that the reason for this restriction is that performance of the surveillance would 1) remove a required offsite circuit from service, 2) perturb the electrical distribution systems, and 3) challenge plant safety systems.

SR 3.8.1.12 is restricted from being performed in MODES 1 or 2 by a similar Note. The TS Bases for SR 3.8.1.12 state, in part, that the reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and as a result, plant safety systems.

4.0 TECHNICAL ANALYSIS

4.1 General Basis

The HPCS Power System is self-contained except for access to the preferred source of offsite power, by connection through the plant AC power distribution system, and for the initiation signal source (see FSAR Section 8.3.1.1.4.2). The loads supplied by this system are only loads associated with Division III of the Emergency Core Cooling System (ECCS). They consist of the HPCS pump, HPCS Standby Service Water Pump, related motor operated valves, diesel support equipment and Division III DC equipment. For a complete listing of loads see FSAR Table 8.3-3. Therefore, during the performance of the surveillance tests contained in this change request only Division III equipment can be directly affected.

The requested change is limited to Division III related components due to the complicated nature of the surveillance tests involved for Division I and II. The risk of performing the noted required surveillance tests during plant operation is not significantly greater than the risk associated with the performance of other DG surveillance tests required by the Technical Specifications but which are not prohibited from being performed during plant operation. This conclusion is based on; (1) the Grand Gulf AC power supply and associated protection features, (2) plant experience with the performance of testing required per the affected SR, (3) administrative controls that minimize plant risks during performance of the affected testing, and (4) the low probability of a significant voltage perturbation during such testing.

Entergy Corporation is a member of the Southeastern Electric Reliability Council (SERC) and adheres to the rules set by the North American Electric Reliability Council (NERC). Through membership in SERC, GGNS ensures grid stability such that there is reasonable assurance that the ability of the Entergy grid to provide offsite power to the Grand Gulf Nuclear Station will not be impaired by the loss of the largest external single supply or the loss of GGNS itself. Further details on grid stability can be found in the FSAR Section 8.2.3.

4.2 Administrative Controls for On-line Maintenance

Grand Gulf Nuclear Station Technical Specifications impose requirements/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 diesel generator. 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 Safety Function Determination Program (SFDP) pursuant to TS 5.5.10 requires that the loss of safety function be protected against.

The GGNS approach to performing maintenance requires that we use a protected division concept. This means that without special considerations we only allow 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.

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 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.) Even if this highly unlikely scenario were to occur, plant safe shutdown capability would still be assured with the two remaining DGs.

4.3 On-line Risk Management

The GGNS Plant Administrative Procedure "01-S-18-6 Risk Assessments of Maintenance Activities" provides procedural requirements to conduct risk assessment for all maintenance activities. 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 10CFR50.65 (a) (4) Maintenance Rule. This program uses a risk evaluation tool to assess the potential risk implications of planned or emergent work activities. This tool warns Planning & Scheduling/Outage and Operations 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 equipment or components. The risk evaluation tool is a comprehensive modeling of important GGNS equipment and allows the site to evaluate the adverse effects of other maintenance activities and its impact on DG maintenance.

4.4 Online Versus Outage Testing

The current Limiting Condition for Operations (LCO) for the HPCS DG is 72 hours but due to the relationship between the DG and the HPCS system, the Technical Specifications allow up to 14 days of inoperability if the Reactor Core Isolation Cooling system is not inoperable. This LCO provides ample time for the performance of the SR requested in this change request. The actual time needed to perform these SR is approximately 36 hours.

The uniqueness of the GGNS design related to the HPCS system and the HPCS DG, along with the three-offsite power feeds*, gives GGNS the necessary margins of safety to make this request. By virtue of the HPCS being a stand-alone system with its dedicated DG and independent distribution system, there is minimal opportunity for the performance of these SR to have any impact on other safety related plant equipment. Also due to the minimal size of the loads associated with the HPCS system there isn't any real potential for this testing to create a perturbation on the grid. Completed test results have shown that the important grid parameters stay within prescribed limits.

*See Background Section 3.0

In comparing the Technical Specification requirements for ECCS and AC Sources during MODES 1, 2, or 3 and MODES 4 or 5 the requirements are more stringent during MODES 1, 2, or 3. Due to the more restrictive criteria during MODES 1, 2, or 3 performing the testing during these MODES is less likely to cause a loss of safety function if something should go wrong during the test.

As described in the FSAR, Section 6.3.4.2.1 "HPCS Testing", the HPCS system can be tested at full flow conditions in any operational condition. Additionally, FSAR, Sections 7.3.1.1.1.3.9 and 7.3.2.1.2.3.1.10 describes the testability of the HPCS instrumentation during normal plant operations. These Sections state that the HPCS control system is capable of being completely tested during normal plant operation to verify that each element of the system, active or passive, is capable of performing its intended function.

4.5 Risk Assessment

During certain portions of the surveillances the DG would not be able to immediately respond to an accident. DG unavailability during the performance of the proposed on-line HPCS DG testing is estimated to be 36 hours. This would be in addition to the normal unavailability that occurs due to current testing and maintenance. Based on this estimate, the increase in average Core Damage Frequency (CDF) and Incremental Conditional Core Damage Probability (ICCDP) is determined as follows:

For the average maintenance model (as specified in RG 1.177), the base core damage frequency for GGNS is 5.46E-6 per year. Conservative estimates of the equivalent yearly core damage probability when the HPCS DG is out of service (for the whole year) can be made utilizing the risk achievement worth for each of the DG. This results in the following CDF estimate:

	CDF on Yearly Basis
Baseline	5.46E-6
DG C OOS	2.90E-5

Average CDF Increase

The average at-power CDF with the additional out of service time for the HPCS DG is computed by adding the CDF for the additional period during which it is out of service with the CDF for the remainder of the year. The change in CDF is calculated as follows:

$$\Delta CDF_{At-Power} = \frac{T_C}{T_{Year}}(CDF_{COOS}) + \left(1 - \frac{(T_C)}{T_{Year}}\right)(CDF_{Base}) - CDF_{Base}$$

where,

CDF_{COOS} is the estimated yearly CDF with the HPCS DG out of service.

T_C is the additional out of service time for the HPCS DG due to the proposed on line testing. This is estimated to be a total of 36 hours per cycle for the diesel. On a yearly basis this number is 24 hours per year with the assumption of an 18 month cycle.

T_{Year} is the number of hours in a year (8760 hours).

CDF_{Base} is the baseline annual average CDF with the current average unavailability of the DG.

Therefore, the ΔCDF associated with this change is:

$$\Delta CDF_{At-Power} = \frac{24\,hrs}{8760\,hrs}(2.9E-5/yr) + \left(1 - \frac{(24hrs)}{8760\,hrs}\right)(5.46E-6/yr) - 5.46E-6/yr$$
$$= 6.45E-8/yr$$

This value for ΔCDF is significantly smaller than the RG 1.174 guidance of less than 1.0E-6/year for very small CDF increases.

ICCDP

The incremental conditional core damage probability (ICCDP) can be computed using the definition in RG 1.177. In terms of the above defined parameters, the definition of ICCDP associated with the HPCS DG out of service is as follows:

$$ICCDP = \frac{T}{8760\,hrs/yr}(CDF_{COOS} - CDF_{Base})$$

For this calculation, the total additional out of service time (36 hours) is considered.

$$ICCDP = \frac{36\,hrs}{8760\,hrs/yr}(2.9E-5/yr - 5.46E-6/yr)$$
$$= 9.67E-8$$

This value for ICCDP is significantly smaller than the RG 1.177 guidance of 5.0E-7 for a small quantitative impact.

ΔLERF and ICLERP

Calculation of ΔLERF and ICLERP are not necessary as these two are a fraction of ΔCDF and ICCDP and both ΔCDF and ICCDP are below the respective ΔLERF and ICLERP significance guidance from RG 1.174 and RG 1.177.

PSA Quality

The original Individual Plant Examination (IPE) was developed by Entergy with the assistance of Science Applications International Corporation (SAIC) and was submitted to the NRC in 1992. It was revised in 1997 and was renamed the GGNS PSA, Revision 1. The above evaluations were performed using results from the Revision 1 GGNS PSA. This revision of the PSA is currently undergoing a major revision but results are not yet available. However, an independent assessment of the Revision 1 GGNS PSA has been completed to ensure that the GGNS PSA was comparable to other PSA programs 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 Certification Report in November 1997. The models and methodology used in Revision 1 of the GGNS PSA were included in the PSA Certification review. The quality of the PSA and completeness of the PSA documentation were also assessed. The certification team found that the GGNS PSA is fully capable of addressing issues requiring risk significance determination with a few enhancements. Because the proposed changes to the GGNS Facility Operating License have only a small impact on HPCS DG unavailability, any enhancements made to the GGNS PSA are not expected to significantly impact the overall conclusions of the above evaluations.

External Events

By letter dated November 15, 1995, Entergy Operations, Inc. (EOI) submitted the Individual Plant Examination for External Events (IPEEE) for GGNS. In the IPEEE, seismic was addressed using a seismic margins methodology, fire was addressed using fire PRA methods (i.e., EPRI TR-105928, Fire PRA Implementation Guide), and the other events were addressed by demonstrating conformance to the 1975 SRP. EOI received the NRC Staff Evaluation Report by letter dated March 16, 2001, in which the staff concluded that the aspects of seismic events, fires and high winds, floods and other (HFO) events were adequately addressed. Of the considered events, fire and seismic are initiators with the most potential for an induced loss of offsite power. A loss of offsite power is relevant to the proposed changes because of the potential increase in DG unavailability.

GGNS was classified in NUREG-1407 as a reduced scope plant of low seismicity and emphasis was placed on conducting seismic walkdowns for the IPEEE. Therefore, a seismic loss of offsite power (LOOP) initiator frequency was not determined but can be estimated 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 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. Therefore, the seismic LOOP initiator frequency is approximately two orders of magnitude lower than the LOOP initiating event frequency (3.9E-2) times the GGNS four hour non-recovery probability of offsite power (6E-2) used in the GGNS base internal events PSA model (that is, 3.9E-2/yr X 6E-2 = 2.3E-3/yr). Based on this estimate and the relatively insignificant risk impact of the proposed changes to the internal events PSA model, the impact of the proposed changes to seismic risk is considered to be insignificant.

While PSA techniques were used to develop core damage frequencies associated with internal fires, the results from the IPEEE 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 vulnerability does not exist. The fire PSA was not developed to the same level of detail as the internal events PSA. Therefore, the fire CDF reported in the IPEEE, as a general rule, should not be combined with, or directly compared to the internal events analysis. A review of the Fire PSA scenarios indicates that approximately 14.6% of the fire CDF (1.3E-6/year) is associated with a fire induced LOOP event. This is compared to a 42.5% contribution (2.3E-6/year) from LOOP initiators for the base internal events PSA. These frequencies are relatively close and since additional HPCS 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 internal events PSA CDF. Since the impact of the change on internal events CDF and ICCDP is well under the acceptance guidance, there is no need to quantitatively evaluate the impact on fire risk. It is expected to be non-risk significant also.

5.0 REGULATORY ANALYSIS

5.1 Applicable Regulatory Requirements/Criteria

The proposed changes have been evaluated to determine whether applicable regulations and requirements continue to be met. The application provides sufficient information to demonstrate that the request does not alter compliance with any applicable regulatory requirement or criteria. The Grand Gulf Nuclear Station's Final Safety Analysis Report Chapter 8 Section 8.3.1.2 provides an analysis of the plant design against the applicable regulatory requirements. This change request affects the description of compliance to GDC 18 provided in FSAR Section 8.3.1.2.b.2 in that Entergy is now proposing to perform the functional test during normal operations. Entergy has carefully reviewed the requirements of GDC 18 and has determined that it only defines that the electrical system be designed such that testing can be performed and does not stipulate when testing should be conducted.

Entergy has determined that the proposed changes do not require any exemptions or relief from regulatory requirements, other than the TS, and do not affect conformance with any GDC differently than described in the FSAR.

5.2 No Significant Hazards Consideration

Entergy Operations, Inc. (Entergy) hereby requests the following amendment for Grand Gulf Nuclear Station, Unit 1 (GGNS). Entergy proposes to amend Technical Specification (TS) 3.8.1, "AC Sources – Operating" to remove the remaining MODE restrictions for testing the High Pressure Core Spray (HPCS) Diesel Generator 13 (DG 13). The proposed change would remove the restriction associated with Surveillance Requirements (SR) that prohibits performing the required testing in MODES 1, 2, or 3. In conjunction with the letter referenced above this request will remove all current restrictions associated with testing of DG 13. The specific SR addressed in this submittal includes; SR 3.8.1.11, 3.8.1.12, 3.8.1.16, and 3.8.1.19. Entergy Operations, Inc. has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The HPCS DG and its associated emergency loads are accident mitigating features, not accident initiating equipment. Therefore, there will be no impact on any accident probabilities by the approval of the requested amendment.

The design of plant equipment is not being modified by these proposed changes. As such, the ability of the DG to respond to a design basis accident will not be adversely impacted by these proposed changes. The capability of the DG to supply power in a timely manner will not be compromised by permitting performance of DG testing during periods of power operation. Additionally, limiting testing to only one DG at a time ensures that design basis requirement for backup power is met, should a fault occur on the tested DG. Therefore, there would be no significant impact on any accident consequences.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   No new accident causal mechanisms would be created as a result of NRC approval of this amendment request since no changes are being made to the plant that would introduce any new accident causal mechanisms. Equipment will be operated in the same configuration with the exception of the plant MODE in which the testing is currently conducted. This amendment request does not impact any plant systems that are accident initiators; neither does it adversely impact any accident mitigating systems.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No.

   Margin of safety is related to the confidence in the ability of the fission product barriers to perform their design functions during and following an accident situation. These barriers include the fuel cladding, the reactor coolant system, and the containment system. The proposed changes to the testing requirements for the HPCS DG do not affect the operability requirements for the DG, as verification of such operability will continue to be performed as required. Continued verification of operability supports the capability of the DG to perform its required function of providing emergency power to plant equipment that supports or constitutes the fission product barriers. Consequently, the performance of these fission product barriers will not be impacted by implementation of this proposed amendment.

   In addition, the proposed changes involve no changes to setpoints or limits established or assumed by the accident analysis. On this and the above basis, no safety margins will be impacted.

   Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, Entergy concludes that the proposed amendment(s) present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

5.3 Environmental Considerations

The proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

Attachment 2

GNRO-2002/00006

Proposed Technical Specification Changes (mark-up)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	-------------------NOTES------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---	(NOT APPLICABLE TO DG 13)
	Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. energizes auto-connected shutdown loads, 3. maintains steady state voltage ≥ 3744 V and ≤ 4576 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	------------------NOTES------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for ~~unplanned~~ events that satisfy this SR. ---	(NOT APPLICABLE TO DG 13)
	Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and: a. In ≤ 10 seconds after auto-start and during tests, achieves voltage ≥ 3744 V and frequency ≥ 58.8 Hz; b. Achieves steady state voltage ≥ 3744 V and ≤ 4576 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz; c. Operates for ≥ 5 minutes; and d. Emergency loads are auto-connected to the offsite power system.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.16	-------------------NOTE------------------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. -- (NOT APPLICABLE TO DG 13) Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	------------------NOTES------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---	(NOT APPLICABLE TO DG 13)
	Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. energizes auto-connected emergency loads, 3. achieves steady state voltage ≥ 3744 V and ≤ 4576 V, 4. achieves steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	18 months

(continued)

Attachment 3

GNRO-2002/00006

Changes to Technical Specification Bases Pages

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.3

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be not within its required Allowable Value specified in Table 3.3.5.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analyses. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than the setting accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 4.

SR 3.3.5.1.4 and SR 3.3.5.1.5

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency of SR 3.3.5.1.4 and SR 3.3.5.1.5 is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.1, LCO 3.5.2, LCO 3.8.1, and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage (EXCEPT FOR DIVISION III WHICH CAN BE TESTED IN ANY OPERATIONAL CONDITION) and the ~~potential for unplanned transients if the~~

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.4 (continued)

losses, and RPV pressure present during LOCAs. These values may be established during pre-operational testing. The Frequency for this Surveillance is in accordance with the Inservice Testing Program requirements.

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance test verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCS, LPCS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup, and actuation of all automatic valves to their required positions. This Surveillance also ensures that the HPCS System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(EXCEPT FOR DIVISION III WHICH CAN BE TESTED IN ANY OPERATIONAL CONDITION)

This SR is modified by a Note that excludes vessel injection/spray during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3) takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

INSERT A

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for DG 11 and DG 12. For DG 13, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. NOTE 2 IS NOT APPLICABLE TO DG 13. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥5 minutes. The 5 minute period provides sufficient time to demonstrate

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

stability. SR 3.8.1.12.d ensures that emergency loads are energized from the offsite electrical power system on an ECCS signal without loss of offsite power.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the loading logic for loading onto offsite power. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the offsite power system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 18 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

INSERT A

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for DG 11 and DG 12. For DG 13, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. NOTE 2 IS NOT APPLICABLE TO DG 13. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR has been modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 1 hour at full load conditions or until operating temperatures stabilized prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. The DG 11 and 12 load band is provided to avoid routine overloading of the TDI DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.16

As required by Regulatory Guide 1.9 (Ref. 3) this Surveillance ensures that the manual synchronization and load transfer from the DG to each required offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the undervoltage logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the load sequence logic is reset.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3) and takes into consideration plant conditions required to perform the Surveillance.

INSERT A

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

(NOTE IS NOT APPLICABLE TO DG13)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 13), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading is not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.18 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance during these MODES would challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. For the purposes of this Surveillance the DG 13 autoconnected emergency loads are verified to be energized in ≤ 20 seconds. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 18 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 18 months.

INSERT A

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for DG 11 and DG 12. For DG 13, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. NOTE 2 IS NOT APPLICABLE TO DG13. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

This surveillance is performed when the unit is shut down and its 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

(continued)

INSERT A

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related distribution subsystem) connected to one offsite source, while the remaining safety-related systems are aligned to another offsite source. This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations.