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Jerry C. Roberts
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GNRO-2002/00032

June 19, 2002

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

SUBJECT: Grand Gulf Nuclear Station, Unit 1
Docket 50-416
Supplemental Information for License Amendment Request
Removal of Operating MODE Restrictions for Performing
Emergency Diesel Generator Testing (TAC No. MB3487)

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:

By the letter referenced above, Entergy Operations, Inc. (Entergy) proposed a change to the Grand Gulf Nuclear Station, Unit 1 (GGNS) Technical Specification (TS) to remove MODE restrictions from certain surveillances for the Emergency Diesel Generators (EDGs).

On March 19, 2002, Entergy and members of your staff conducted a telephone conference to discuss the proposed change. In particular sections 4.4 "Testing Pursuant to SR 3.8.1.9 and SR 3.8.1.10" and 4.5 "Testing Pursuant to SR 3.8.1.17" of the application were discussed. During the discussion it became apparent that a supplemental response was needed to clarify the information provided in the original application. Entergy's supplemental information is provided in Attachment 1.

There are no Technical Specification changes proposed by this supplemental response. The original no significant hazards considerations included in the reference is still valid and is not affected by any information contained in the supplement. There are no new commitments contained in this letter.

Entergy still 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.

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If you have any questions or require additional information, please contact Mr. Ron Byrd at extension (601) 368-5792.

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

Sincerely,

J. C. Roberts
Director, Nuclear Safety Assurance
Grand Gulf Nuclear Station, Unit 1

JCR/RWB

Attachment: Supplemental Technical Information

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Attachment 1 to

GNRO-2002/00032

Supplemental Information

**Supplemental Information Related to
Proposed Amendment to
Remove MODE Restrictions for EDG Testing**

Question 1:

Testing Pursuant to SR 3.8.1.9 and SR 3.8.1.10

You stated that the analysis of bus voltage traces taken from previous load rejection tests have shown that the voltage drop which occurs, is such that voltage during "transient" remains well above the minimum required voltage for plant loads, and typically recovers well within 2 seconds. Thus, the voltage "transient" experienced by loads on the affected bus is minor. However, these tests were conducted during plant shutdown when the plant voltages were significantly higher resulting in less perturbation in the electrical distribution system. The proposed testing will be performed during power operation when the expected voltage will be lower, and could caused more perturbation in the electrical distribution system. Please explain how the perturbation during power operation is comparable to the previous test results.

Also, demonstrate that the voltage drop on the safety bus after load rejection is well above the setpoints of a degraded grid and loss of voltage relays.

Response:

The expected voltage during power operations at the ESF 4.16 kV buses, where the sensors monitor for voltage degradation/loss, is near nominal to slightly above nominal. One reason for this is the FSAR nominal 500 kV source voltage is 1.02 per unit, and another is the relatively low loading factor for the Station Service Transformers. The FSAR minimum anticipated 500 kV source voltage is 0.992 per unit. This establishes significant margin between the available bus voltages and the degraded voltage trips, which are nominally 90% for Divisions I/II, and nominally approximately 88.5% for Division III, on a 4.16 kV base. The expected decrease for bus voltage as a result of performing the load rejection test is less than a 2% reduction on the respective ESF bus. Thus, even with the test performed at FSAR minimum anticipated 500 kV grid conditions, the expected bus voltage would remain above the degraded voltage setpoints. The time delay features for the degraded/loss of voltage schemes will ensure that the very brief transient will have settled out well before these timers would allow an actuation due to any transient effects. The minimumtime delay for degraded voltage for Divisions I/II is 9 seconds, and for Division III is 4 seconds. As stated on the telephone conference the transient lasts well under 2 seconds. The loss of voltage sensors has setpoints, nominally in the 70% bus voltage range, which are well below the degraded voltage sensors. The expected drop in bus voltage due to the proposed test will still maintain the available voltage significantly above these settings.

Question 2:

Testing Pursuant to SR 3.8.1.17

SR 3.8.1.17 requires verification that, with an Emergency Diesel Generator (EDG) operating in test mode and connected to its bus, an actual or simulated Emergency Core Cooling System (ECCS) initiation signal overrides the test mode by returning the EDG to ready-to-load operation, and automatically energizing the emergency loads from offsite power. If this SR was to be performed during power operation, how do you demonstrate compliance with SR 3.8.1.17.b without sequencing safety loads during power operation?

Also, describe how the ECCS signal is simulated during power operation to perform this surveillance without disturbing the redundant EDGs.

Response:

As stated in the Technical Specification Bases for SR 3.8.1.17, "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. The testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified."

Entergy used this philosophy in developing the procedure currently used for conducting this surveillance during shutdown. The current procedure does not shed and sequence back on the ECCS pumps. Shedding and sequencing of the other loads demonstrates compliance with SR 3.8.1.17.b. The actual loads affected include the Standby Service Water pump and DG auxiliaries, which are already in service for support of the DG operation, and the remaining loads exclusive of the associated ECCS pumps. These ECCS pumps are tested as part of SR 3.8.1.12, which provides the necessary overlap to demonstrate compliance with SR 3.8.1.17.b.

It is Entergy's intention to continue to use this philosophy to perform this surveillance on line. The development of the procedure to support performing this testing online would evaluate each of the loads that are shed and sequenced following a LOCA signal, and on a case-by case basis determine if they need to be defeated in order to prevent plant perturbations. The requirement for SR 3.8.1.17.b would continue to be maintained via overlap with other testing (primarily SR 3.8.1.12). This will eliminate the potential for significant transients to the plant when this request is granted.

The design of Grand Gulf Nuclear Station Unit 1 allows total separation of the redundant divisions during performance of these tests. The test method also allows the test(s) to be conducted on only a minimal number of systems or components selected using the criteria described in the previous paragraph. While ensuring capability by overlapping steps, certain components can be prevented from functioning while checking associated logic circuits, providing additional means for minimizing the potential impact of performing these surveillances.

The Division I and Division II load shedding and sequencing (LSS) panels are solid-state logic boards, which are totally redundant (one per Engineered Safety Features (ESF) Division). These panels are independent of EDGs 11 and 12. ESF Division III, which is served by EDG 13, does not have a LSS panel. A complete description of the system design is provided in section 8.3.1.1.3, "Load Shedding and Sequencing on ESF Buses" of the Final Safety Analysis Report.

When the EDG is operated in the test mode (as per SR 3.8.1.17) the EDG is started manually in the non-emergency mode in accordance with the system operating instruction or surveillance procedure. During these types of runs, the LSS panels are not involved and remain in their normal condition (i.e., ready to respond to a bus under-voltage or loss of coolant accident (LOCA) signal). In the EDG test mode, the EDG is running with all protective trips functioning and will respond to a signal from the LSS panel on a LOCA signal. If this signal appears during a test, interlocks to the LOCA sensing circuit (LSS panels) cause the EDG to automatically terminate paralleled operation with the offsite sources by opening the output breaker and EDG non-critical protective trips are bypassed. The confirmation that the EDG test mode is overridden in this manner can be conducted without causing perturbations to the plant by individually defeating selected components.

As far as auto-connecting the emergency loads to the offsite power system on an ECCS initiation signal, the LSS logic performs this function the same regardless of whether the EDG is in standby condition or operating in a test mode. Therefore, whether the auto-connect load test is conducted under 3.8.1.12.d or 3.8.1.17.b is inconsequential. In fact the BWR6 Standard TS, NUREG-1434, only requires this test to be listed in SR 3.8.1.12.d since SR 3.8.1.17.d is bracketed. However, other BWR6s have preferentially placed the requirement in 3.8.1.17.d rather than 3.8.1.12.d. GGNS is the only BWR6 with the SR in both locations. We believe this supports additional flexibility in performance of the SR as noted in the Bases for both 3.8.1.12.d and 3.8.1.17.d.

In reference to the above discussion, the NRC staff also requested that Entergy provide a general discussion on SR testing sequence and overlap philosophy. This information is provided below.

<u>SR Testing Sequence and Overlap Philosophy</u>

Entergy's position is that particular SRs may be performed in sequential or overlapping steps at separate scheduled times provided the SRs are completed for the applicable function within the specified frequencies. Failure to meet a SR within the specified frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO. By relying on this premise the surveillance or portions thereof are performed on a relative fixed time period (allowing for grace periods) and the reliability of components are ensured by the repetitive nature of the surveillances.

When a TS amendment such as the one requested is granted, SR due dates may be extended from the outage by using the available grace period. The only other method to move the testing out of the outage is to perform the given surveillance early (i.e., sooner than required) and then establish the frequency from its completion. Once the new performance period is established, then the amount of time between the main and the overlapped surveillance becomes fixed. This establishes connectivity and reliability relationships between the two surveillances, which will maintain the overall reliability of the associated components.

As far as sequencing is concerned, Entergy's position is that, unless otherwise specified by the Technical Specifications, the sequencing of SRs is discretionary and is left up to the utility to decide how to best test the safety function. From a reliability perspective, the frequency is more important and must be maintained for each SR. The sequencing could even be swapped occasionally without affecting validity of the surveillances.

This philosophy is best illustrated in the following time line example of surveillance A and B. In this example, SR A and SR B are currently performed during an outage. SR A will now be performed on-line while SR B will continue to be performed each outage.

ORIGINAL SCHEDULED DATE	FOUR MONTHS LATER	18 MONTHS FROM ORIGINAL	22 MONTHS FROM ORIGINAL	36 MONTHS FROM ORIGINAL	40 MONTHS FROM ORIGINAL
SR A&B DURING OUTAGE	SR A	SR B	SR A	SR B	SR A

This example shows that the length of time between testing of any of the associated logic is now shorter than the original 18 months. This should aid in detection of equipment problems earlier, especially if some functions are tested during each of the surveillances.

In summary, the surveillance frequency and testing sequence are only important to the particular function for which the surveillance is applicable. The SR frequency assures that the system is operable whether performed one month ago or 18 months ago. Surveillance overlap scheduling should not be a concern since the portion that the surveillance affects is always verified to be operable within the surveillance frequency irrelevant from the overlapping test schedule.