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Rick J. King
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RBG - 46067

February 12, 2003

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

SUBJECT: River Bend Station, Unit 1
Docket No. 50-458
Supplement to Amendment Request
LAR 2002-17, River Bend Nuclear Station Proposed Amendment of Facility Operating License to Remove Operating Mode Restrictions for Performing Emergency Diesel Generator Testing, TAC No. MB5093.

REFERENCES: Letter RBG-45950 dated May 14, 2002 from Entergy to USNRC, LAR 2002-17, River Bend Nuclear Station Proposed Amendment of Facility Operating License to Remove Operating Mode Restrictions for Performing Emergency Diesel Generator Testing

Dear Sir or Madam:

By Reference 1, Entergy Operations, Inc. (Entergy) proposed a change to the River Bend Station, Unit 1 (RBS) Operating License and Technical Specifications (TSs) associated with revising several of the Surveillance Requirements (SRs) pertaining to testing of the Division 3 standby diesel generator (DG) and manual transfer test for offsite circuits.

Based on their review, the NRC provided a request for additional information (RAI) containing draft questions being considered by members of your staff. Responses to those questions are provided in Attachment 1.

There are no new commitments made in this letter. If you have any questions or require additional information, please contact Greg Norris at 225-336-6391.

A001

I declare under penalty of perjury that the foregoing is true and correct. Executed on February 12, 2003.

Sincerely,

RJK/gpn

Attachments:
1. Response to Request For Additional Information

cc: U. S. Nuclear Regulatory Commission
Region IV
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NRC Senior Resident Inspector
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U.S. Nuclear Regulatory Commission
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Bcc:

File Nos.: G9.5, G9.42

File: LAR 2002-17

File: RBF1-03-0012

Attachment 1

To

RBG – 46067

Response to Request for Additional Information

Response to Request for Additional Information Related to Operating Mode Restrictions for Performing Emergency Diesel Generator Testing

1. You stated that completing the testing of the High Pressure Core Spray (HPCS) DG and the HPCS System during normal hours eliminate approximately 12 hours of Operator intensive testing during an outage. The staff is concerned that conducting these tests during power operation would unnecessarily increase DG unavailability during power operation which may impact your unavailability goals established for satisfying the maintenance rule. Please provide your revised DG unavailability goals established for meeting the maintenance rule and justify increasing the unavailability of DG.

Response:

The unavailability goal for the HPCS DG is currently 2.5% or less. As discussed in response to question 2, there is no need to revise the goal due to the on-line testing. Please note that although the operators may be involved in the testing for approximately 12 hours, the DG is only expected to be unavailable for 2 or 3 hours during the test. In addition, the HPCS system is only expected to be unavailable for 12 hours during the test.

2. HPCS DG unavailability during the performance of the proposed on-line testing is provided in Table 1 of the submittal to be 12 hours/cycle for performing of SRs 3.8.1.13b, 3.8.1.9, 3.8.1.10 and 3.8.1.17. What is the total unavailability of HPCS DG for the performance of the remaining SRs?

Response:

The unavailability of the HPCS DG during the performance of the remaining SRs occurs only when DG is placed into the Maintenance mode to prepare it for a planned start. This applies to any of the "start/run" SRs - 3.8.1.2, 3.8.1.7, 3.8.1.11, 3.8.1.12, 3.8.1.14, 3.8.1.19, and 3.8.1.20. In a typical 18-month cycle, the total estimated unavailability for these SRs is10 hours or less. Therefore the maximum estimated unavailability for all SRs should be approximately 12 hours per cycle.

3. During performance of SRs 3.8.1.9 and 3.8.1.10, as related to full load rejection and largest single load rejection tests, explain how the perturbation during power operation is comparable to the previous test results which were performed during shutdown when system voltages were relatively higher. In addition demonstrate that the voltage drop on the safety bus after load rejection is well above the set points of degraded and loss of voltage relays. In addition, discuss what largest single load is rejected for HPCS DG.

Response:

A note in the RBS Technical Specification for Sections 3.8.1.9 and 3.8.1.10 states that the surveillance cannot be performed in Modes 1 or 2, but credit can be taken for unplanned events that satisfy this SR. The unplanned events as defined in the bases include post corrective 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.

As the RBS Technical Specification Bases for Sections 3.8.1.9 and 3.8.1.10 state; "The reason for the note is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution system that could challenge the continued steady state operation and, as a result, plant safety systems."

RBS has performed these surveillances in Mode 1 for such corrective maintenance and found no indication of excess perturbation of the electrical distribution system that challenge continued steady state operation.

RBS has test data for the Division III diesel generator full load reject test performed with the unit off line and with the standby bus voltage monitored. No excessive voltage transient was recorded that would challenge the loss of voltage or degraded voltage relays. The bus voltage incurred a small step change of less than 1.5% downward with no noticeable overshoot.

The actual Div. III test data was approximated in a preliminary dynamic ETAP (Electrical Transient Analyzer Program) PowerStation simulation of the load reject test under off-line conditions. The difference between on-line and outage testing was the initial bus voltage before the test. The absolute magnitude of the step change was essentially the same in both cases.

The on-line load reject analysis was run at the worst case anticipated grid voltage under double contingency grid conditions with RBS off-line (0.989 P.U.) per the latest system study. Conservatism is added by the fact that the grid voltage included the LOCA loading on the standby buses. In this extreme case, there was considerable margin between the final bus voltage and the degraded voltage setpoint. There is an approximate one minute timer on the degraded voltage relay to allow the grid to recover. The loss of voltage relay has a three second time delay, whose calibration is checked every eighteen months by surveillance. The loss of voltage relay is set at approximately 73% bus voltage. It is highly unlikely that this voltage could be reached under an on line load reject scenario.

If a LOCA signal is received while testing a diesel generator that is connected to its bus, the diesel output breaker automatically opens. This allows the diesel to be reset from the test mode to the emergency mode, and protective trips are bypassed as designed. This initiates re-sequencing of the diesel loads if the off-site source does not continue to carry the bus.

Discussion of the single largest load is provided in the response to question 5.

4. SRs 3.8.1.11 and 3.8.1.19 require de-energization of emergency buses. The staff is concerned that performing the surveillance during power operation would unnecessarily remove a required offsite circuit from service and perturb the electrical distribution system. Provide your justification for not performing this surveillance during shutdown as currently performed. In addition, describe how LOOP and SI signals are generated without disturbing operation.

Also, SRs 3.8.1.11 and 3.8.1.19 require verification on an actual or simulated LOOP signal and an actual or simulated LOOP in conjunction with an actual or simulated emergency core cooling system (ECCS) initiation signal, respectively, that HPCS DG supplies permanently connected and auto-connected loads for > 5 minutes. Describe in detail how HPCS pump will be operated during these tests without disturbing plant operation.

Response:

The HPCS system is a stand alone system with a dedicated diesel generator and independent distribution system. 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 which allows testing without injecting into the reactor vessel. The only component that would not be tested during plant operation would be the HPCS injection motor operated valve.

Due to the minimal size of the loads associated with the HPCS system, there is also minimal potential for creating a perturbation on the grid. This is discussed in the response to question 3.

Test signals during the surveillances are generated by connecting an Emergency Core Cooling System Test Switch to the HPCS Logic Test Receptacle on panel H13-P625. This panel, H13-P625, is the HPCS instrumentation cabinet in the main control room. Additional test signals, such as service water pump initiation and the loss of power signals are generated using calibration units for a specific function, and by manually tripping the HPCS bus supply breaker. The control logics associated with these tests are Division 3 only, and do not impact other divisional components.

During testing, the HPCS pump is operated in a test return configuration with its reactor vessel injection pathway isolated. During current off-line testing, this is done with the injection path manually isolated. As the manual isolation is located in the drywell, on-line testing would be performed with the injection line motor operated valve closed and de-energized. This testing would be similar to quarterly in-service testing that is already performed during plant operation.

5. SR 3.8.1.18 verifies that the sequence timing is within +10% of design for each load sequence timer. Please clarify what is sequenced on the HPCS DG and why.

Response:

Whenever the High Pressure Core Spray (HPCS) DG is given an ECCS LOP initiation, all the Division 3 bus loads are stripped (Also see question 6). This occurs, such that if the bus is down (Loss Of Power) and the loads must reconnect to the DG, the DG will have its full power range, full fuel input travel range, to pick up the largest load first. This first, largest, load is the HPCS pump (1995 KW motor) and a number of small ("permanently connected") loads. These are about 78-80 percent of the DG's 2600 KW continuous rating.

The DG Ventilation System Exhaust Fan, HVP-FN3A, is sequenced on 20 seconds after the diesel starts. Standby Service Water pump, SWP-P2C, is sequenced to come on 30 seconds after the diesel starts to allow the HPCS pump to come up to speed and allow bus voltage to recover. The service water pump discharge valve, SWP-MOV40C, opens after the service water pump starts.

USAR Table 8.3.3 gives the Div. 3 load table.

6. Describe how during performance of SR 3.8.1.17 when the HPCS DG is in test mode and connected to its bus, an actual or simulated ECCS signal returns the DG as well as the HPCS system to their standby conditions.

Response:

SR 3.8.1.17a requires "returning DG to ready-to-load operation" when an ECCS (LOCA) initiation signal overrides its test mode while it is connected to the bus. This is not the same as returning the system to a standby condition.

When the HPCS system is configured for this testing, the DG is paralleled to the HPCS (Division 3) bus with all normal trips enabled and loaded to ≥1995 KW with the HPCS pump and other loads. The actual or simulated LOCA signal automatically sends a start signal to the DG, which is already running. The same signal picks up interposing relays to block the engine trips, enables the LOCA time delay for degraded voltage relays, disables the voltage balance protection and trips the diesel generator output breaker. The HPCS pump and other loads continue operate, powered from the Division 3 bus fed from its normal source. The DG continues to run, unloaded, and the non-safety related protective trips will be disabled. If a concurrent or subsequent Loss of Power (LOP) occurs, the controls strip the Division 3 bus. Approximately 5 seconds later, the DG breaker will close and start the HPCS pump followed by the sequencing of the ventilation fan, the service water pump and its discharge MOV.

Thus the diesel defaults to a suitable ready-to-load condition (running, at slightly elevated voltage and frequency but still within IEEE-323 / NEMA MG-1 limits), as the controls strip the Div. 3 bus on the ECCS initiation. This is simply a partial or full load reject; the worst case being a full reject.

In addition to the above questions, the NRC also requested, by email dated February 5, 2003, information related to potential future changes of power supply from the preferred to normal station service transformers. Specifically, it was asked if this configuration is going to be changed in the future, and how the licensee would address that.

Response:

RBS has no recent data related to conducting Division 3 EDG testing while connected to a normal station service transformer. The Division 3 EDG bus is connected to a preferred station service transformer. Revision to this configuration such that the Division 3 EDG bus is connected to the normal station service transformer will require technical evaluation of the equipment configuration and capabilities as well as an evaluation of the change under 10 CFR 50.59.