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RBG-46072

March 14, 2003

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

SUBJECT: River Bend Station, Unit 1
Docket No. 50-458
License Amendment Request
LAR 2003-02, River Bend Nuclear Station Proposed Amendment of Facility Operating License to Remove Operating Mode Restrictions for Performing Division 1 and 2 Emergency Diesel Generator Load Reject Testing

REFERENCE: 1. Letter RBG-45950 from P.D. Hinnenkamp to U.S. NRC Document Control Desk, "License 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", dated May 14, 2002.

Dear Sir or Madam:

Pursuant to 10CFR50.90, Entergy Operations, Inc. (Entergy) hereby requests the following amendment for River Bend Station, Unit 1. EOI requests modification of the River Bend Technical Specifications to revise the Surveillance Requirements (SRs) pertaining to testing of the Division 1 and 2 standby diesel generator (DG). The proposed change would modify specific restrictions associated with these SRs that prohibit performing required testing in Modes 1 and 2. The affected SRs are SR 3.8.1.9 and SR 3.8.1.10.

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.

The proposed change includes new commitments The NRC has approved similar Technical Specification changes for other plants For example, Grand Gulf, Perry and Clinton have each received similar license amendments on September 5, 2002, February 24, 1999, and October 2, 2000, respectively.

Entergy requests approval of the proposed amendment by August 31, 2003 to allow for implementation and application of the requested changes prior to a scheduled fall diesel maintenance outage. Once approved, the amendment shall be implemented within 30 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 Greg Norris at 225-336-6391.

I declare under penalty of perjury that the foregoing is true and correct. Executed on March14, 2003.

Sincerely,

Paul D. Hinnenkamp
Vice President, Operations
River Bend Station, Unit 1

PDH/GPN

Attachments:
1. Analysis of Proposed Technical Specification Change
2. Proposed Technical Specification Changes (mark-up)
3. Changes to TS Bases pages
4. List of Regulatory Commitments

cc: U. S. Nuclear Regulatory Commission
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Attachment 1

RBG-46072

Analysis of Proposed Technical Specification Change

1.0 DESCRIPTION

This letter is a request to amend Operating License NPF-47, for River Bend Station, Unit 1 (RBS).

The proposed change will revise Technical Specification (TS) 3.8.1, "AC Sources - Operating" to modify Surveillance Requirements (SRs) pertaining to the testing of the Division 1 and 2 standby diesel generators (DG). Specifically, changes will revise Technical Specification (TS) 3.8.1, "AC Sources - Operating" in order to modify specific MODE restrictions for performance of SRs for the Division 1 and 2 DGs. This would allow the performance of SR 3.8.1.9 and SR 3.8.1.10 for Division 1 and 2 DGs during any MODE of plant operation. This change will allow greater flexibility in scheduling these SRs and will allow the performance during non-outage periods.

Entergy requests approval of the proposed amendment by August 31, 2003 to allow for implementation and application of the requested changes prior to a scheduled fall DG maintenance outage.

2.0 PROPOSED CHANGE

SR 3.8.1.9: Revise Note 1 to remove the MODE restrictions for all DGs. This will also delete changes in this note currently proposed by reference 1. This SR requires demonstrating that the diesel generator (DG) can reject its largest load while maintaining margin to the overspeed trip.

SR 3.8.1.10: Revise the Note to remove the MODE restrictions for all DGs. This will also delete changes in this note currently proposed by reference 1. This SR requires demonstrating that the DG can reject its full load without the DG tripping or its output voltage exceeding a specified limit.

The proposed changes to SRs 3.8.1.9 and 3.8.1.10 will allow performance of the testing during Modes 1 or 2. These proposed changes have minimal risk implications and are intended to provide flexibility in scheduling EDG maintenance activities, reduce refueling outage duration, and improve EDG availability during plant shutdowns. Entergy desires to perform these SRs, as required, following future online DG maintenance outages. Such an outage is currently scheduled for the Fall of 2003, during which Entergy plans to perform DG governor modifications that will require these retests to be performed.

In summary, Entergy proposes to amend Technical Specification (TS) 3.8.1, "AC Sources - Operating" to remove specific MODE restrictions applicable to the testing of the Division 1 and 2 DG within SR 3.8.1.9 and SR 3.8.1.10. These changes will allow the performance of these SRs for the Division 1 and 2 DG during any MODE of plant operation. This will allow greater flexibility in scheduling these SR and will allow the performance during non-outage times.

The proposed changes to the TS are reflected in the annotated TS pages provided in Attachment 2. Associated changes to the TS Bases are indicated in Attachment 3. The proposed TS Bases changes are for information only and will be controlled by TS 5.5.11, "Technical Specifications (TS) Bases Control Program."

3.0 BACKGROUND

River Bend 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 RBS consists of the offsite power sources and the onsite standby power sources, i.e., diesel generators (DGs) 1A, 1B and 1C. 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 River Bend Station supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 4.16 kV ESF bus. Each ESF bus has two 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 RBS switchyard from the transmission network. From the switchyard two electrically and physically separated circuits provide AC power to each 4.16 kV ESF 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. A detailed description of the offsite power network and circuits to the onsite Class 1E ESF buses is found in Updated Safety Analysis Report, (USAR) Chapter 8.

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 on an ESF bus degraded voltage or under-voltage 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 DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident such as a LOCA.

A detailed description of the onsite power network is found in USAR, Chapter 8, section 8.3 " Onsite Power System".

For Divisions I and II, prior to automatically connecting the DG to the ESF bus (i.e., closing DG output breaker), the breakers connecting the buses to the offsite sources are automatically 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 automatically 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 USAR Section 8.3.1.1.3.

Presently, SRs 3.8.1.9 and 3.8.1.10 are required to be performed while the plant is shut down. This is enforced by a note preceding each of the SRs in the Technical Specifications, which states in part that the surveillance shall not be performed in Mode 1 or 2. The TS Bases state that the reason for this restriction is to prevent unnecessary perturbations to the electrical distribution systems which could challenge steady state operation and thus plant safety systems if the SR was performed with the reactor critical.

The safety function of the Standby Diesel Generators is to ensure the availability of power to standby buses to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

Each diesel generator is provided with an overspeed trip to prevent damage to the engine. Recovery from the transient of a loss of a large load or full load reject could cause diesel engine overspeed, which, if excessive, might result in the trip of the engine. Full load reject may occur due to system faults or inadvertent breaker tripping. As a result, the RBS Technical Specifications have surveillances to demonstrate the capability of the diesel generator to reject the largest load while maintaining a specified margin to overspeed trip, and to demonstrate the capability to reject the full load (i.e. maximum expected accident load) on the diesel generator without overspeed tripping or exceeding predetermined voltage limits.

SR 3.8.1.9 and 3.8.1.10 are currently modified by a note. The note states this Surveillance shall not be performed in Modes 1 and 2, however, credit can be taken for unplanned events that satisfy this SR. The stated 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. The unplanned events, for which credit may be taken, include post corrective actions that require performance of this surveillance to restore this component to OPERABLE.

4.0 TECHNICAL ANALYSIS

4.1 General Basis

Although the TS Bases, as currently written, state that the reason for the SR Note (for SRs 3.8.1.9 and 3.8.1.10) is to preclude the potential for perturbations of the electrical distribution system during plant operation, reconsideration of this basis has determined that the noted concern is unwarranted with respect to requiring the affected SRs to be performed only during shutdown conditions. This conclusion is based on (1) the River Bend AC power supply and associated protection features (2) industry and plant experience with the performance of testing required per the affected SRs, (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.

Such testing only makes the DG unavailable for responding to an accident during portions of the testing. The risk of performing the noted required surveillances during plant operation is not significantly greater than the risk associated with the performance of other DG surveillances required by the Technical Specifications but which are not prohibited from being performed during plant operation. Surveillance Requirements 3.8.1.9 and 3.8.1.10 are performed by paralleling the DG in test with offsite power, similar to the existing monthly run of the DG, which is conducted with the plant on line. Further, performance of the required testing at power would not result in a challenge to any plant safety system.

These conclusions are based on the following:

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

River Bend does not currently have historical data for the actual response of the Division 1 and 2 emergency buses during this testing. However, historical test data for the Division 3 diesel generator full load reject tests performed with the unit off line with the standby bus voltage monitored was reviewed. 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. 3 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 model showed equivalent results were expected for Division I and Division II full load reject tests under unit on-line or 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.

As discussed above, River Bend does not currently have historical data for the actual response of the Division 1 and 2 emergency buses during this testing. The response of the emergency bus voltage during load reject testing is not a data point that is necessary for the performance of the SR. The collection of this bus voltage response data has been scheduled for the next performance of these surveillances, which will occur during RF11, in the Spring of 2003. River Bend will use that test data to confirm the conclusions stated above.

4.2 Administrative Controls for On-line Maintenance

River Bend 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 River Bend Station (RBS) 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. RBS 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 is possible for operator action to be taken to manually reset the affected lockout relay so that the DG can be restarted.) Even if this 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 RBS Plant Administrative Procedure, ADM-0096 "Risk Management Program Implementation and On-line Maintenance Risk Assessment", provides procedural requirements to conduct risk assessment for all maintenance performed while in MODES 1, 2 or 3. 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 identifies for Planning & Scheduling/Outage personnel that plant risk goals are being approached or would be exceeded by proposed work plans. These administrative controls contained in the above procedure minimize any potential to allow work on redundant DGs. The risk evaluation tool is a comprehensive modeling of important RBS equipment and allows the site to evaluate the adverse effects of other maintenance activities and its impact on DG maintenance.

4.4 Testing Pursuant to SR 3.8.1.9 and SR 3.8.1.10

For performance of the load rejection tests per SRs 3.8.1.9 and 3.8.1.10, the typical approach taken is to load the tested DG to the required load when connected to the grid and then open the DG output breaker. An alternate method for performing SR 3.8.1.9 is to trip the associated largest single load. Opening of the DG output breaker separates the DG from its associated emergency bus and allows the offsite circuit to continue to supply the bus. This evolution has little impact on plant loads. The power system loading during such testing is within the rating of all transformers, switchgear, and breakers, both before and after the load rejection, and as further explained below, performance of the load rejection SRs does not cause any significant perturbations to the electrical distribution systems as the DG is separated from the bus.

During operation at River Bend, the emergency buses are currently tied to the preferred station service transformers fed from the switchyard. This is the configuration maintained during plant shutdown when the load reject testing is currently conducted. The probability for a grid disturbance to occur during the timeframe of a test performed per SR 3.8.1.9 or SR 3.8.1.10 is low since the occurrence of a grid disturbance is independent of the testing. Regardless, protective relaying for the diesel generator would be available to protect the diesel generator while it is connected to the grid. This configuration, with the DGs connected to the grid, is the same during monthly DG surveillances. In addition, the protection instrumentation (required to be Operable per TS 3.3.8.1, "Loss of Power (LOP) Instrumentation") for sustained grid low-voltage conditions would be available to respond to such a condition.

4.5 Risk Assessment

Much of this risk assessment information in this section was provided to the NRC by reference 1. It contains a risk evaluation related to the ECCS surveillances for DGs. The load reject tests, performed per SR 3.8.1.9 and SR 3.8.1.10, associated with Division 1 and 2 are contained within the ECCS surveillances, STP-309-0601 and STP-309-0602.

It is only during certain portions of these surveillances that the DGs are not able to immediately respond to an accident. DG unavailability during the performance of the proposed on-line DG testing is summarized in Table 2, with the longest unavailability time of 8.0 hours. Based on this, the greatest Incremental Conditional Core Damage Probability (ICCDP) per RG 1.177 is determined as follows.

For the average maintenance model (as referenced in RG 1.177), the base core damage frequency for RBS is 3.39E-6 per year, based upon Revision 3A of the RBS Level 1 PRA which was implemented in the Fall of 2002. Conservative estimates of the equivalent yearly core damage probability when a DG is out of service (for the whole year) can be made utilizing the risk achievement worth for each of the DGs. This results in the following CDF estimates:

TABLE 1

	CDF on Yearly Basis
Baseline	3.39E-6
DG A OOS	8.14E-6 (RAW = 2.4)
DG B OOS	6.78E-6 (RAW = 2.0)
DG C OOS	6.10E-6 (RAW = 1.8)

Average CDF Increase

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

$$\Delta CDF_{At-Power} = \frac{T_A}{T_{Year}}(CDF_{AOOS}) + \frac{T_B}{T_{Year}}(CDF_{BOOS}) + \frac{T_C}{T_{Year}}(CDF_{COOS}) + \left[1 - \frac{(T_A + T_B + T_C)}{T_{Year}}\right](CDF_{Base}) - CDF_{Base}$$

where,

CDF_{AOOS}, CDF_{BOOS}, CDF_{COOS} are the estimated yearly CDF with the corresponding DG out of service.

T_A, T_B, T_C are the additional out of service times for each DG due to the proposed on line testing. This is estimated to be a total of 12 hours per cycle for each diesel. On a yearly basis this number is 8 hours per diesel 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 DGs.

Therefore, the ΔCDF associated with this change is:

$$\Delta CDF_{At-Power} = \frac{8hrs}{8760hrs}(8.14E-6/yr) + \frac{8hrs}{8760hrs}(6.78E-6/yr) + \frac{8hrs}{8760hrs}(6.10E-6/yr)$$

$$+ \left[1 - \frac{(8hrs + 8hrs + 8hrs)}{8760hrs}\right](3.39E-6/yr) - 3.39E-6/yr$$

$$= 9.91E-9/yr$$

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.

TABLE 2
DG Unavailability During Surveillance Testing

	Surveillance Test Procedure/ Description	Applicable Technical Specification	Associated Unavailability	Comments regarding unavailability
1	STP-309-0601, 0602 Div. I, Div. II 18 month ECCS test	SR 3.8.1.13a	4.0 hrs/DG/cycle	Unavailability estimate is based on the average time to install LOCA signal and to conduct testing The DG remains unavailable until the tests are completed.
2	STP-309-0603 Div III ECCS Test	SR 3.8.1.13b	4.0 hrs/DG/cycle	Unavailability estimate is based on the average time to install LOCA signal and to conduct testing The DG remains unavailable until the tests are completed.
3	STP-309-0601, 0602, 0603 Div. I, II, III 18 Month ECCS Test	SR 3.8 1.9, SR 3.8 1.10, SR 3 8 1.17	8 0 hrs/DG/cycle	Unavailability estimate is based on the average time to install LOCA signal and to bar engine and check for moisture and complete testing
			Total Unavailability Hours per cycle 12 hrs/DG/cycle	Item 1 describes testing on Division I and II DG and item 2 describes testing on Division III DG Item 3 describes testing on all three Divisions, therefore adding items 1 and 3 or 2 and 3 gives the total for unavailability hours per DG

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 Division 1 (DG A) out of service is as follows:

$$ICCDP_A = \frac{T_A}{8760 hrs/yr}\left(CDF_{AOOS} - CDF_{Base}\right)$$

There is a similar expression for each of the other DGs, but since the CDF for DG A bounds that of the other 2 DGs, it is used for the calculation of ICCDP. The total increase in out of service time (12 hours) is also used for this calculation.

$$ICCDP = \frac{12 hrs}{8760 hrs/yr}\left(8.14E-6/yr - 3.39E-6/yr\right)$$

$$= 6.5E\text{-}9$$

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

<u>ΔLERF and ICLERP</u>

Calculation of ΔLERF (Delta Large Early Release Frequency) and ICLERP (Incremental Conditional Large Early Release Probability) 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 PSA model for RBS was first developed for the Individual Plant Examination (IPE) that was submitted to the NRC by letter RBG-38077 dated February 1, 1993 , 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 RBS IPE by letter RBC-47152 October 17, 1996, wherein the NRC staff concluded that the RBS IPE submittal met the intent of Generic Letter 88-20. No major weaknesses were identified.

An independent assessment of the RBS PSA, using the Self-Assessment Process developed as part of the Boiling Water Reactor Owners' Group (BWROG) PSA Peer Review Certification Program, was completed to ensure that the RBS PSA was comparable to other PSA programs in use throughout the industry. To this end, a PSA Certification Team completed an inspection and review of the RBS PSA in April 1998 and completed a PSA Certification Report in October 1998. Included in the PSA Certification review were the models and methodology used in the RBS PSA. The quality of the PSA and completeness of the PSA documentation were also assessed. The certification team found that the RBS PSA is fully capable of addressing issues such as those associated with extending the Division I and Division II EDG AOT from 72 hours to 14 days, with a few enhancements. The RBS PSA has also benefited from subsequent plant reviews of the other BWR-6 plants. Additional information on the PSA Certification review has been provided to the NRC in RBS letters RBG-45832, "License Amendment Request (LAR) 2001-027, Emergency Diesel Generator Extended Allowed Outage Time" and RBG-45934, "Supplement to Amendment Request LAR 2001-027, Emergency Diesel Generator Extended Allowed Outage Time, TS 3.8.1."

External Events

Fire

As stated in NUREG-1407, the IPEEE was meant to be a vulnerability screening analysis rather than a full scope probabilistic risk assessment. 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 IPE. The CDF values generated for the IPEEE are intended to show that the CDF is low enough that a vulnerability does not exist. The evaluation of external events and internal fires contains some very large uncertainties. In many cases, these uncertainties led to the application of conservative assumptions to bound the accident and prove that no vulnerabilities exist.

By letter dated June 30, 1995, Entergy Operations, Inc. (EOI), submitted the Individual Plant Examination for External Events (IPEEE) for RBS. EOI received the NRC Staff Evaluation Report by letter dated June 13, 2001, in which the staff concluded that the aspects of seismic events, fires, and high winds, floods, and other events were adequately addressed.

RBS developed a Fire PSA to address the fire portion of the IPEEE. The same PSA model was used as in the IPE submittal. The basic approach used was to find a target set of equipment associated with a particular fire scenario. These are components that may be directly impacted by the fire scenario or may be impacted by fires affecting cables that power or control the components. Based upon the fire scenario, existing initiators from the plant full power internal events PSA were selected to represent the type of plant shutdown that could occur. The list of initiating events and basic events representing the components lost were input as failures into the full power PSA model to derive conditional core damage probabilities (CCDPs) given a fire. This CCDP was typically multiplied by the fire ignition frequency to derive an estimated core damage frequency for a particular fire scenario. The table below provides the fire areas identified as important[1].

Important Fire Areas

Fire Area	Description of Area	Core Damage Frequency
C-25	Main Control Room	4.87E-06/yr
C-15	Division I Standby Switchgear Room	4.75E-06/yr
C-17	Control Room Ventilation Room	4.56E-06/yr
C-4	ACU West Room	3.31E-06/yr
AB-2/Z-2	HPCS & HPCS Hatch Area	2.23E-06/yr
ET-1	B-Tunnel East	1.48E-06/yr
AB-1/Z-4	Auxiliary Building West Side Crescent Area	1.26E-06/yr
NS-4	Normal Switchgear Room 1A	1.10E-06/yr
T-2/Z-2	Turbine Building General Area Elevation 67'-6"	1.52E-06/yr

In the Level I PSA model used for the IPEEE, there were 33 functional accident sequence groupings. Only 16 of these functional sequences applied to the Fire PSA and only 5 functional sequences contributed more than 1% to any of the remaining fire areas. The top 5 functional sequences were:

TBU – Fire-induced LOOP followed by a failure of DG A & B. HPCS was assumed to fail due to a loss of SSW return during a SBO. RCIC was assumed to fail due to a loss of flow and level instrumentation. These assumptions were conservatively made due to lack of cable routing information for these components. Without any injection, core damage occurs.

TW - Transient followed by failure of all decay heat removal. High pressure coolant make-up fails immediately, but the vessel is successfully depressurized and low pressure makeup is initially successful. However, without decay heat removal, containment failure due to overpressurization eventually occurs. Containment failure results in a harsh environment in the auxiliary building which causes failure of the SRV's which re-pressurizes the vessel and fails the operating low pressure systems. Core damage occurs.

[1] The fire risk for the cable spreading rooms was determined to be minimal for the following reasons:
1. There are separate cable spreading rooms for Division I and Division II.
2. The cable spreading rooms contain no cabinets or other fire source.
3. The cable spreading rooms are equipped with fire protection sprinklers

TUV - Transient followed by a failure of all high pressure and low pressure coolant makeup. Power conversion is assumed to fail due to a lack of cable routing information. Without coolant makeup, core damage occurs.

TUX - Transient followed by a failure of all high pressure coolant make-up. Reactor depressurization fails, preventing the use of low pressure coolant make-up systems. Power conversion is assumed to fail due to lack of cable routing information. Without coolant makeup, core damage occurs.

S2UV –Transient with one stuck open relief valve followed by a failure of all high pressure and low pressure coolant makeup. Without coolant makeup, core damage occurs.

Because the diesel generators are only required to mitigate loss of offsite power events in the PSA analysis, the only fire scenarios that could increase in risk due to the DG AOT extension are those that would lead to the LOOP. Random occurrences of LOOPs concurrent with internal fire events are considered probabilistically insignificant. The individual fire areas identified as important were reviewed for sequences contributing to the CDF to identify those that involve the fire induced LOOP initiator. Two fire areas were identified, Fire Area C25 (main control room) and Fire Area T-2/Z-2 (turbine building general area elevation 67'-6"). These two fire areas are discussed in more detail below.

C-25 Main Control Room

For main control room fires, it was assumed that a cabinet fire that was contained to a non-divisional cabinet would result in a loss of offsite power and loss of all non-divisional equipment. This assumption was conservative since the majority of non-divisional cabinets do not contain equipment related to offsite power and power distribution. Also, the EPRI Fire Events Database shows that the electrical cabinet fires that have occurred at US nuclear plants are generally benign.

For main control room fires that result in evacuation, it is assumed that all offsite power is lost. The unavailability of a single DG then dominates the CCDP.

The CDF for the MCR non-evacuation scenarios for fires in non-divisional cabinets was 1.62E-8/yr. The CDF for the MCR non-evacuation scenarios for fires in divisional cabinets was 1.15E-6/yr. Therefore, the total CDF for the MCR non-evacuation scenarios for all cabinets is 1.17E-6/yr. The CDF for MCR fires that result in evacuation was 3.70E-6/yr. Therefore, the total CDF for MCR fires is 4.87E-6.

T-2/Z-2 Turbine Building General Area elevation 67'-6"

The north east corner of Fire Area T-2/Z-2 has a horizontal run of cable (cable tray 1TC352N) that provides power to components fed by Reserve Station Service (RSS) #1 and resides about six inches away from cabinets MCC 1NHS-MCC1E and –MCC1F. Additionally, cable tray 1TC350N, which provides power to components fed by RSS #2, intersects 1TC352N at a 90 degree angle in close proximity to the same cabinets. A cabinet fire would potentially damage both the Division I and Division II offsite power cables. This is conservatively assumed to result in a loss of offsite power. The CDF for fire area T-2/Z-2 is 1.52E-6/yr.

This fire area is in the turbine building and does not contain any safe shutdown equipment. If a fire were to occur in this fire area while an EDG was out of service, the remaining DGs would not be impacted.

In summary, the contribution of fire induced LOOP scenarios to the overall fire CDF of 2.5E-5/yr is 5.24E-6/yr, or approximately 21%. Taking a diesel out of service for maintenance could impact these scenarios, but not in a way that is significantly different than a LOOP from the internal events PSA. Fire-induced LOOP sequences progress in a manner similar to a LOOP with failure of offsite power recovery. However, the fire risk values take no credit for the ability to connect EDG C to the Division I bus. In fact, the fire PSA model gave little credit for recovery of off-site power since it was assumed that the non-divisional power cables were damaged.

Seismic

Per the RBS IPEEE, "RBS is classified in NUREG-1407 as a reduced scope plant of low seismicity; therefore, emphasis was placed on conducting detailed seismic walkdowns." Since RBS did not perform a seismic PSA analysis for the IPEEE; the seismic LOOP initiator frequency was not previously determined. The likelihood of a seismic event at River Bend is on the order of 1E-5/yr (Ref. NUREG-1488). Maximum ground acceleration for both horizontal and vertical motion for the safe shutdown earthquake (SSE) is 0.1 g (RBS USAR Section 2.5.2.6). 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 External Events," estimates the median peak ground acceleration at which these ceramic insulators are lost to be approximately 0.25 g. Using this value, the conclusion can be reached that the seismic LOOP initiator is over an order of magnitude less than the LOOP initiating event frequency times the 4 hour non-recovery probability for AC power used in the base PSA model.

Industry experience also supports this conclusion. At least in recent history, seismic events appear to be a relatively minor contributor to the industry LOOP frequency. Evidence of this is provided in EPRI Report TR-110398, "Losses of Offsite Power at U.S. Nuclear Plants – Through 1997." This report records no LOOP events caused by seismic events, even though the database includes over a thousand years of unit operating experience and includes a period of time that had noteworthy earthquakes.

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 River Bend Station USAR 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 USAR Section 8.3.1.2.2.1 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 SAR.

5.2 No Significant Hazards Consideration

The proposed change will revise Technical Specification (TS) 3.8.1, "AC Sources – Operating" to modify Surveillance Requirements (SRs) pertaining to the testing of the Division 1 and 2 standby diesel generators (DG). Specifically, changes will revise Technical Specification (TS) 3.8.1, "AC Sources – Operating" in order to modify specific MODE restrictions for performance of Surveillance Requirements (SR) for the Division 1 and 2 Diesel Generators. This would allow the performance of all SRs for the DGs during any MODE of plant operation. This will allow greater flexibility in scheduling these SRs and will allow the performance during non-outage times.

Entergy Operations, Inc. has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) 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 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 requirements for backup power is met, should a fault occur on the tested DG. Therefore, there would be no significant impact on any accident consequences.

Based on the above, the proposed change to permit certain DG surveillance tests to be performed during plant operation will have no effect on accident probabilities or 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 conducted. This amendment request does not impact any plant systems that are accident initiators; neither does it adversely impact any accident mitigating systems.

   Based on the above, implementation of the proposed changes would not create the possibility of a new or different kind of accident from any accident 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 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

RBG-46072

Proposed Technical Specification Changes (mark-up)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	-----------------------NOTE----------------------- 1. ~~This Surveillance shall not be performed in MODE 1 or 2. However,~~ credit may be taken for unplanned events that satisfy this SR. 2. If performed with DG synchronized with offsite power, it shall be performed at a power factor ≤ 0.9 -- Verify each DG rejects a load greater than or equal to its associated single largest post accident load and following load rejection, the engine speed is maintained less than nominal plus 75% of the difference between nominal speed and the overspeed trip setpoint or 15% above nominal, whichever is lower.	18 months
SR 3.8.1.10	-----------------------NOTE----------------------- ~~This Surveillance shall not be performed in MODE 1 or 2. However,~~ credit may be taken for unplanned events that satisfy this SR. -- Verify each DG operating at a power factor ≤ 0.9 does not trip and voltage is maintained ≤ 4784 V for DG 1A and DG 1B and ≤ 5400 V for DG 1C during and following a load rejection of a load ≥ 3030 kW and ≤ 3130 kW for DGs 1A and 1B and ≥ 2500 kW and ≤ 2600 kW for DG 1C.	18 months

(continued)

Attachment 3

RBG-46072

Changes to Technical Specification Bases Page

(Information Only)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load while maintaining a specified margin to the overspeed trip. The referenced load for DG 1A is the 917.5 kW low pressure core spray pump; for DG 1B, the 462.2 kW residual heat removal (RHR) pump; and for DG 1C the 1995 kW HPCS pump. The Standby Service Water (SSW) pump values are not used as the largest load since the SSW supplies cooling to the associated DG. If this load were to trip, it would result in the loss of the DG. As required by IEEE-308 (Ref. 13), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower. For the River Bend Station the lower value results from the first criteria. The 18 month frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9).

Note 1 states:

This SR has been modified by two Notes. ~~The reason for Note 1 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.~~ 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 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.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load, i.e., maximum expected accident load, without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event and continue to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 9) and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by a Note. ~~The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, 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 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.

(continued)

Attachment 4

RBG-46072

List of Regulatory Commitments

List of Regulatory Commitments

The following table identifies those actions committed to by Entergy in this document. Any other statements in this submittal are provided for information purposes and are not considered to be regulatory commitments.

COMMITMENT	TYPE (Check one)		SCHEDULED COMPLETION DATE (If Required)
	ONE-TIME ACTION	CONTINUING COMPLIANCE	
The collection of this bus voltage response data [for Division 1 and 2 DGs] has been scheduled for the next performance of these surveillances, which will occur during RF11, in the Spring of 2003. River Bend will use that test data to confirm the conclusions stated above.	x		RF11