September 25, 2002

Mr. Paul D. Hinnenkamp
Vice President - Operations
Entergy Operations, Inc.
River Bend Station
P. O. Box 220
St. Francisville, LA 70775

SUBJECT: RIVER BEND STATION, UNIT 1 - ISSUANCE OF AMENDMENT RE: EMERGENCY DIESEL GENERATOR EXTENDED ALLOWED OUTAGE TIME (TAC NO. MB3041)

Dear Mr. Hinnenkamp:

The Commission has issued the enclosed Amendment No. 125 to Facility Operating License No. NPF-47 for the River Bend Station, Unit 1. The amendment consists of changes to the Technical Specifications in response to your application dated September 24, 2001, as supplemented by letters dated April 22 and July 29, 2002.

The amendment extends the allowed outage time for a Division I or Division II Emergency Diesel Generator (EDG) from 72 hours to 14 days. The changes are intended to provide flexibility in scheduling EDG maintenance activities, reduce refueling outage duration, and improve EDG availability during plant shutdowns.

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

Sincerely,

/RA/

Michael K. Webb, Project Manager, Section 1
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-458

Enclosures: 1. Amendment No. 125 to NPF-47
2. Safety Evaluation

cc w/encls: See next page

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Accession No.: ML022590314 *No significant change from input.

OFFICE	PDIV-1/PM	PDIV-1/LA	SPSB/SC	EEIB/SC	OGC	PDIV-1/SC
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DATE	9/25/02002	9/25/02	8/21/02	9/6/02	9/24/02	9/25/02

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ENTERGY GULF STATES, INC. **

AND

ENTERGY OPERATIONS, INC.

DOCKET NO. 50-458

RIVER BEND STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 125
License No. NPF-47

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

    A. The application for amendment by Entergy Gulf States, Inc.* (the licensee) dated September 24, 2001, as supplemented by letters dated April 22 and July 29, 2002, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

    B. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission;

    C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

    D. The issuance of this license amendment will not be inimical to the common defense and security or to the health and safety of the public; and

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* Entergy Operations, Inc. is authorized to act as agent for Entergy Gulf States, Inc., and has exclusive responsibility and control over the physical construction, operation and maintenance of the facility.

**Entergy Gulf States, Inc., has merged with a wholly owned subsidiary of Entergy Corporation. Entergy Gulf States, Inc., was the surviving company in the merger.

E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and Paragraph 2.C.(2) of Facility Operating License No. NPF-47 is hereby amended to read as follows:

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 125 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. EOI shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. The license amendment is effective as of its date of issuance and shall be implemented within 60 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Robert A. Gramm, Chief, Section 1
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: September 25, 2002

ATTACHMENT TO LICENSE AMENDMENT NO. 125

FACILITY OPERATING LICENSE NO. NPF-47

DOCKET NO. 50-458

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by Amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
3.8-2	3.8-2
3.8-3	3.8-3

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 125 TO FACILITY OPERATING LICENSE NO. NPF-47

ENTERGY OPERATIONS, INC.

RIVER BEND STATION, UNIT 1

DOCKET NO. 50-458

1.0 INTRODUCTION

By application dated September 24, 2001, as supplemented by letters dated April 22 and July 29, 2002, Entergy Operations, Inc. (the licensee) requested changes to the Technical Specifications (TSs) (Appendix A to Facility Operating License No. NPF-47) for the River Bend Station, Unit 1 (RBS). The proposed changes would extend the allowed outage time (AOT) for a Division I or Division II Emergency Diesel Generator (EDG) from 72 hours to 14 days. The changes are intended to provide flexibility in scheduling EDG maintenance activities, reduce refueling outage duration, and improve EDG availability during plant shutdowns.

The April 22 and July 29, 2002, supplemental letters provided clarifying information that did not change the scope of the original *Federal Register* notice (66 FR 64292, published December 12, 2001) or the original no significant hazards consideration determination.

2.0 BACKGROUND

The licensee has proposed a change to the action requirements defined in the TSs as they relate to the limiting conditions for operation (LCO) for the EDGs. Specifically, the proposed change would revise TS 3.8.1, "Electrical Power Systems - AC [Alternating Current] Sources--Operating," to increase the AOT for one inoperable EDG from the current 72 hours to 14 days. The proposed AOT extension request is founded on the findings of deterministic and probabilistic risk assessments. The U.S. Nuclear Regulatory Commission (NRC) staff held several teleconferences with the licensee to discuss the proposed TS changes. By letter dated March 12, 2002, the NRC staff sent a request for additional information. By letters dated April 22 and July 29, 2002, the licensee provided the requested information. In addition, the licensee also submitted changes to the Bases section.

The proposed changes would allow Division I and Division II EDGs in Modes 1, 2, or 3 to be out of service (OOS) for 14 days rather than the current limit of 3 days (72 hours). This 11-day extension would also be applied to the maximum time allowed for any combination of required AC sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. The main purpose of the proposed change is to allow on-line performance of 18-month EDG maintenance activities that would normally be performed during refueling outages. In addition, the extended AOT may also be used for corrective maintenance that may be needed to resolve EDG deficiencies that are discovered during surveillance to avert a potential unplanned plant shutdown.

The licensee indicated that increasing the AOT from the current 3 days to 14 days is not risk-significant, and that the risk associated with a shutdown transition to repair an EDG is comparable to the risk of performing the maintenance on-line. The proposed change would also improve EDG availability and reliability during shutdown.

The proposed AOT is founded on the findings of both deterministic and probabilistic risk assessment (PRA).

3.0 EVALUATION

General Design Criterion (GDC) 17, "Electric Power Systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to Part 50 of Title 10 of the *Code of Federal Regulations* (10 CFR) requires, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of structures, systems, and components (SSCs) that are important safety. The onsite system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. The offsite power system is required to be supplied by two physically independent circuits that are designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. In addition, this criterion requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as a result of loss of power from the unit, the offsite transmission network, or the onsite power supplies.

GDC 18, "Inspection and Testing of Electric Power Systems," requires that electric power systems that are important to safety be designed to permit appropriate periodic inspection and testing. Section 50.36 of 10 CFR, "Technical specifications," requires a licensee's TSs to establish LCOs, which include AOT for equipment that is required for safe operation of the facility.

Section 50.65 of 10 CFR, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," requires that preventive maintenance activities not reduce the overall availability of the SSCs. Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," provides guidance with respect to operating restrictions (i.e., AOTs) if the number of available AC sources is less than that required by the TS LCO. In particular, this guide prescribes a maximum AOT of 72 hours for an inoperable AC source.

The offsite and onsite power systems at RBS are designed to comply with the requirements of GDC 17 and GDC 18. As described by the licensee's amendment request dated September 24, 2001, the RBS AC electrical power sources consist of three onsite standby Class 1E power sources (EDGs) and two offsite power sources that are designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. 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 supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E ESF bus. Each bus has two separate and independent offsite sources of power and a dedicated onsite EDG. 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.

The onsite standby power source for each ESF bus is a dedicated EDG that starts automatically on a loss-of-coolant accident (LOCA) signal or an ESF bus degraded voltage or undervoltage signal. The onsite AC emergency power system has the required redundancy; meets the single-failure criterion; is testable; and has the capacity, capability, and reliability to supply power to all required safety loads.

In addition, a 200-kilowatt (kW), 480-Volt (V) AC, trailer-mounted, portable diesel generator (the station blackout (SBO) diesel), is provided as an alternate source of AC power to the backup battery charger. The SBO diesel can be manually connected to the backup charger through a permanently-installed switch. Through the backup battery charger, the SBO diesel can then provide power to either the Division I or II 125-V direct current batteries during an SBO.

3.1 Deterministic Evaluation

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

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

Station Blackout

The staff evaluated the licensee’s request to extend the AOT to determine whether it would erode the decrease in severe accident risk that was achieved by implementing the SBO requirements in 10 CFR 50.63, "Loss of all alternating current power." RBS is classified as a

4-hour coping plant with 95 percent EDG reliability. The licensee stated that the proposed change will not erode the decrease in severe accident risk that was achieved by implementing the SBO Rule, and that the extended EDG AOT will not impact the SBO coping analysis at RBS. The assumptions used in the SBO analysis regarding reliability of the EDGs will be unaffected by the proposed change, since the licensee will continue to perform preventive maintenance and testing to maintain the reliability assumptions. The staff agrees that the results of the SBO analysis will be unaffected by this change.

Emergency Diesel Generator Availability Due to On-line Maintenance

The staff evaluated the proposed change to ensure that the overall availability of the EDGs will not be significantly reduced as a result of increased on-line preventive maintenance activities, and that the 14-day AOT will be consistent with the objectives and intent of the Maintenance Rule. The licensee stated that EDG reliability and availability are monitored and periodically evaluated in relationship to the Maintenance Rule to ensure that EDG outage times do not degrade operational safety over time. The RBS availability goal is 97.5 percent. The EDG availability for the current cycle (18 months) is approximately 98.5 percent. The licensee stated that, in practice, the actual OOS time is minimized to ensure that Maintenance Rule availability performance criteria are not exceeded. This ensures that the overall availability of the EDGs will not be unnecessarily reduced as a result of maintenance activities.

The Maintenance Rule performance goal for reliability is no more than one maintenance-preventable functional failure (MPFF) per division in a rolling 18-month period. In the past 18 months, the EDGs have not failed to start in any of the 82 demands. The Division I EDG has had no functional failures. The Division II EDG has had two functional failures in the past 18 months; however, only one of these failures was an MPFF.

Alternate Alternating Current Source

The licensee stated that the Division III EDG can be cross-connected to either Division I or Division II AC buses to provide an alternate source of power for an SBO or in the event of a loss of offsite power (LOOP) when one EDG is in the extended outage and the other EDG becomes unavailable. This cross-connection can be accomplished within two hours. The Division III EDG has a 2000-hr rating of 2850 kW. The rating of the Division I and II EDGs is 3130 kW. When the Division III EDG is cross-connected to the Division I bus, it can carry all of the Division I automatically connected loads except the low-pressure core spray pump. Both Division I standby service water (SSW) pumps can be powered by the Division III EDG. The Division I SSW pump (SWP-P2C) is normally powered by the Division III EDG.

When the Division III EDG is cross-connected to the Division II bus, it can carry all of the Division II loads except residual heat removal (RHR) pump C, which is used only for the low pressure coolant injection (LPCI) mode of operation, and one of the Division II SSW pumps, if Division I pump SWP-P2C is still powered by the Division III EDG. This provides a margin of 255 kW. Only two SSW pumps in each division are required; the Division I pump SWP-P2C is secured to allow both Division I and II SSW pumps to be operated.

The licensee stated that in the SBO analysis the high-pressure core spray (HPCS) system is not relied upon as an injection source to the reactor vessel during an SBO. The reactor coolant system inventory control during the initial phases of an SBO will be provided by the Reactor Core Isolation Cooling (RCIC) system. Therefore, the HPCS EDG can be used to power safety loads on either Division. The RHR system success criterion for the shutdown cooling (SDC) or suppression pool cooling (SPC) modes of operation is that one of the two available RHR trains equipped with RHR Heat Exchangers is capable of removing decay heat. The RHR system can remove heat by operating in either SDC mode or SPC mode. The Division I EDG is the normal supply for RHR pump A, and the Division II EDG is the normal power supply for RHR pump B. RHR pump C functions only in the LPCI mode as credited in LOCA analysis. Thus, the Division III EDG is capable of supplying power to the one RHR pump needed for the RHR system to provide decay heat removal for the postulated scenario and capable of supplying all of the loads needed for an SBO or LOOP event.

On the basis of the above considerations, the staff concludes that, in the event of an SBO or a LOOP and failure of the operable EDG during the extended AOT, power can be supplied from the Division III EDG to power all of the needed loads for an SBO or LOOP.

Additional Operational Restrictions

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

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

Regulatory Commitments

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

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

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

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

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

5. HPCS and RCIC systems will not be taken OOS for planned maintenance while EDG A (Division I) or EDG B (Division II) is OOS for extended maintenance.

6. EDG C (Division III) will not be taken OOS for planned maintenance while EDG A (Division I) or EDG B (Division II) is OOS for extended maintenance.

In addition, prior to implementation of the EDG AOT extension, RBS will develop a procedure to align the Division III EDG to the Division I or II bus. The procedure for alignment of the Division III EDG to the Division I or II bus will only be used in the unlikely event of an SBO when immediate recovery of Division I or II bus AC sources is not possible. The procedure will contain the necessary precautions, limitations, and details to minimize the potential for human errors and ensure that it will only be used for its intended purpose.

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

3.1.1 Deterministic Conclusion

The staff has evaluated the proposed changes to determine whether the applicable regulations continue to be met. The staff concludes that, although extending the AOT for an inoperable EDG from the current 72 hours to 14 days is contrary to the recommendations of RG 1.93, the proposed change is acceptable. The staff's conclusion is founded on the following five considerations:

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

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

3. The Division III EDG is available and capable of powering either Division I or Division II loads in the event of an SBO or LOOP.

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

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

Further, the staff believes that regulatory commitments to implement other restrictions and compensatory measures during the extended AOT would ensure the availability of the remaining sources of power and would minimize the occurrence of an SBO. The staff also concludes that the proposed changes will not affect the compliance of RBS with the requirements of GDC 17 and GDC 18. In addition, the staff concludes that it has no objection to the proposed changes to the TS Bases.

3.2 Probabilistic Evaluation

In evaluating the risk associated with changes to an LCO AOT, the NRC staff considers both the average risk of normal operation after the change compared to that before, and the risk of operation during the proposed AOT compared to the average risk of normal operation or the base risk. With regard to the change in the average risk of normal operation associated with a proposed change to a plant's licensing basis, RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated July 1998, provides guidance on the limiting levels of risk that need to be met in order for the staff to consider the proposed risk-informed licensing basis change. This guidance does not address the specific analyses needed for each nuclear power plant activity or design characteristic that may be amenable to risk-informed regulation. However, given that the acceptance guidance of RG 1.174 is met, RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998, provides information on an approach for assessment of TS changes (e.g., estimates of the risk of operation during the increase in the AOT compared to average risk of normal operation) as well as acceptance guidelines for the associated risk change (e.g., a risk change that the staff considers small for a single TS LCO AOT change).

According to RG 1.177, the TS acceptance guidelines specifically for evaluating risk associated with a single TS LCO AOT change are (a) the incremental conditional core damage probability (ICCDP) for equipment OOS (EOOS) is considered small if less than 5.0E-07, and (b) the incremental large early release probability (ICLERP) for EOOS is considered small if less than 5.0E-08. In the context of integrated decision-making, the acceptance guidelines are not interpreted in an overly prescriptive manner. Also, in the context of integrated decision-making, the ICCDP and ICLERP must take into consideration all EOOS that can contribute to risk during the proposed AOT in determining the appropriateness of the change. In addition to consideration of internal events, the impact of a proposed change on risks from fire and external events needs to be evaluated. When adequate supporting information is provided, the staff also considers the risk of shutting down the plant to complete maintenance.

Licensees are encouraged to implement the three-tiered approach discussed in RG 1.177 in assessing risk associated with proposed TS LCO AOT changes. Tier 1, intended to ensure that the change in risk is small, involves an evaluation of the minimum impact on plant risk of the proposed TS change as expressed by the change in core damage frequency (CDF), the ICCDP, and when appropriate, the change in large early release frequency (LERF), and the ICLERP for the case where only the equipment covered by the LCO is OOS. Tier 2, intended to ensure that appropriate restrictions on dominant risk-significant configurations that could exist if equipment in addition to that covered by the TS LCO were to be taken OOS simultaneously for maintenance or testing, involves an identification of potentially high-risk configurations that could exist during the LCO AOT prior to entering the LCO. Tier 3 involves the implementation of an overall configuration risk management program to ensure that other potentially lower probability, but nonetheless risk-significant, configurations resulting from maintenance and other operational activities are identified and compensated for.

As the frequency and length of on-line maintenance outages for risk significant equipment increases, the probability of overlap (both inadvertent and planned) increases, with an associated increase in risk. Hence, an essential feature of this approach is an effective CRMP. With the encouragement of the NRC, licensees typically use the risk management procedures developed for implementation of the Maintenance Rule (in particular, paragraph 10 CFR 50.65(a)(4)) to manage risks associated with TS LCO AOT changes.

Minimum Incremental Risk Estimates (Tier 1)

With the RBS PRA, which is based on cutset and fault tree analysis (CAFTA) software, average risk estimates were made using Revision 3A of the Level 1 PRA model and a modification of the Level 2 PRA model, which is based on Level 1 Revision 2D input. The PRA model was originally developed for the RBS Individual Plant Examination (IPE). It has been updated numerous times since then, the most recent revisions being May 1999 (Revision 2D), January 2001 (Revision 3), and to support this application (Revision 3A). The major model changes incorporated in Revision 2D were to reflect equipment and procedure changes in the RCIC system. Since then, there have been no changes to equipment or procedures that impact the PRA model. The greatest change in the Revision 3 model is modification of event trees to take into account an analysis that shows containment failure occurs sooner on loss of all decay heat removal than previously assumed in Revision 2D. Chief among the changes to the Revision 3A model is incorporation of a new curve for non-recovery of offsite power following a LOOP and taking into account a new procedure (which would be issued prior to implementation of the proposed AOT extension) to cross-tie the Division III EDG to the Division I or II 4.16 kiloVolt bus during an SBO condition. As a result of the PRA revisions, the estimated CDF has decreased from the IPE value of 1.6E-05 per year to the current value of 3.4E-06 per year. Instantaneous risks were estimated with an on-line risk monitor, the EOOS system, with software developed by Data Systems and Solutions for the Electric Power Research Institute. The system incorporates a no-maintenance model which uses the RBS PRA to quantify results when analyzing actual (rather than average) plant configurations; it is used in day-to-day risk management at the plant.

An independent assessment of the RBS PRA, using the Self-Assessment Process developed as part of the Boiling Water Reactor Owners' Group PRA Peer Review Certification Program, was completed in October 1998. The peer review concluded that the PRA was suitable for supporting risk-informed applications such as changes to the TSs provided some enhancements were made, in particular, four of high significance and numerous of less significance. The high significance items were adequately addressed as well as all but a few of the less significant ones; those not addressed are not expected to have a significant impact on initiation or mitigation of LOOP events. The NRC staff did not review the PRA used to support this application nor the details of the licensee's numerical analysis, and has not performed an independent analysis of the proposed change. However, the staff has asked the licensee to perform various calculations, the results of which cause the staff to agree with the peer review group's overall assessment.

With Revision 3A of the PRA model, the licensee estimates the current average CDF and LERF for internal events to be 3.4E-06 and 7.4E-09 per year, respectively, and the change in the average associated with the proposed TS revision to be 4.9E-07 and 2.1E-09 per year, respectively. Based on these levels of risk, RG 1.174 indicates the proposed change can be considered on a risk-informed basis.

The licensee has developed a shutdown PRA, primarily for assessing the risk associated with refueling outage activity (Mode 5), which can also be used for analyzing mid-cycle outage activity after the plant enters cold shutdown (Mode 4). The PRA does not model startup/hot standby (Mode 2) or the orderly transition from on-line power operation (Mode 1) through hot shutdown (Mode 3) to cold shutdown. Mid-cycle outages are not expected to be as risk-significant as refueling outages, due to the limited equipment outages and testing done during mid-cycle outages. The licensee included with this application a rough and bounding-type estimate, assuming the Level 1 PRA is adequate to capture the risk of orderly transition to hot shutdown. This results in an ICCDP of 3.8E-07 for EDG repair, which takes 14 days, and starts with the plant at power and ends with the plant in cold shutdown.

The licensee developed a fire PRA to address the fire portion of the Individual Plant Examination of External Events (IPEEE) (i.e., to perform a screening analysis to identify vulnerabilities if they exist). The CDF generated, however, is not directly comparable to the internal events CDF. The basic approach used was to identify a target set of equipment that may be impacted by a particular fire scenario or may be impacted by fires affecting cables that power or control the equipment. Because the EDGs are only required to mitigate LOOP events in the PRA analysis, the only fire scenarios that could increase in risk due to the EDG AOT extension are those that would lead to the LOOP. The licensee estimates the CDF contribution of fire-induced LOOP scenarios to be 5.2E-06 per year, which is about 21 percent of the overall fire CDF. The impact of taking an EDG OOS for maintenance, based on these scenarios, would be similar to the impact it has on LOOP from the internal events PRA, with failure of offsite power recovery. Considering the conservatism and uncertainty in the estimate, the IPEEE did not identify fire as a vulnerability at RBS.

Because RBS is classified in NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerability," dated May 1991, as a reduced scope plant of low seismicity, the licensee did not perform a seismic PRA of the IPEEE. The licensee estimates that the seismic LOOP initiator frequency is over an order of magnitude less than the LOOP frequency times the 4-hour non-recovery probability for AC power used in the base PRA model. Also, the licensee did not provide a risk analysis of the impact of the proposed change on the external flood risk.

With Revision 3A of the RBS PRA, the licensee has estimated the minimum risk of operation during the LCO for which an EDG is taken OOS for the proposed AOT. The CDF for EDG A (Division I) OOS and for EDG B (Division II) OOS is estimated to be 1.35E-05 and 1.05E-05 per year, respectively. The estimated internal events ICCDP and ICLERP for EDG A (which due to load asymmetries yields larger values) are 3.9E-07 and 1.4E-09, respectively. These values are essentially measures of the importance of the EDG times the proposed AOT. Under these circumstances (i.e., no other EOOS at the time), the estimated ICCDP and ICLERP would be within what the staff considers small.

According to RG 1.177, a Tier 1 assessment is acceptable to the staff if (1) the PRA used is adequate, (2) PRA insights from analysis of various applicable initiating events is adequate, and (3) an internal events estimate of minimum incremental risk probabilities (ICCDP and ICLERP) are within the level of risk the staff considers small for a single TS LCO AOT change. Hence, the licensee's assessment was found to be consistent with staff's Tier 1 guidance.

Avoidance of Risk Significant Plant Configurations (Tier 2)

In order to avoid dominant risk-significant plant configurations before planning to enter an LCO (which has been granted a risk-informed AOT extension), a licensee is expected to perform an assessment to evaluate equipment according to its contribution to plant risk while the equipment covered by the LCO is OOS. The licensee is expected to use the list of equipment so identified to modify the TSs or maintenance procedures so as to avoid high-risk configurations. In the process, compensatory actions that can mitigate the increases in risk associated with the extension should be identified and incorporated in the TSs or procedures.

RBS manages risk with the PRA model, administrative procedure ADM-0096, "Risk Management Program Implementation and On-Line Maintenance Risk Assessment," and operation support procedure OSP-0037, "Shutdown Operations Protection Plan." The EOOS system was used to generate a list of in-service equipment that would be more important as a result of EDG A or EDG B being OOS. This list is shown below.

For EDG A (Division I), the primary systems include:

EDG B and support systems (e.g., EDG heating, ventilation, and air conditioning (HVAC) and fans)
Division II battery charger, battery, and associated breakers and panels
Offsite power (reserve station supply (RSS) #1 and RSS #2)
Division II SSW (including cooling tower fans)
Division I battery charger, battery, and associated breakers and panels
EDG C (Division III) and support systems

For EDG B (Division II), the primary systems include:

EDG A and support systems (e.g., EDG HVAC and fans)
Division I battery charger, battery, and associated breakers and panels
Offsite power (RSS #1 and RSS #2)
Division I SSW (including cooling tower fans)
Division II battery charger, battery, and associated breakers and panels
EDG C (Division III) and support systems

The licensee has stated that procedural and TS controls are already in place to ensure that these systems are not removed from service while an EDG is OOS for extended maintenance. While in the proposed extended EDG AOT, additional elective equipment maintenance or testing that requires the equipment to be removed from service will be evaluated and activities that yield unacceptable results will be avoided. Although the primary value of the list is as an aid in planning preventive maintenance outages, it would be helpful in responding to the need for unplanned (corrective or emergent) maintenance by identifying the equipment whose quick restoration to operable status would have the largest impact on reducing plant risk. This list is used by the licensee primarily as a backup to a real-time EOOS analysis of the actual plant configuration when the LCO is entered.

In addition, the licensee will implement the following restrictions and compensatory measures through administrative procedures to limit the potential risk associated with the extended AOT:

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

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

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

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

5. HPCS and RCIC systems will not be taken OOS for planned maintenance while EDG A (Division I) or EDG B (Division II) is OOS for extended maintenance.

6. EDG C (Division III) will not be taken OOS for planned maintenance while EDG A (Division I) or EDG B (Division II) is OOS for extended maintenance.

According to RG 1.177, a Tier 2 assessment is acceptable if an evaluation of equipment is made such that the equipment is identified according to its contribution to plant risk (or safety) while the equipment covered by the proposed AOT change is OOS, and there are appropriate restrictions on the identified dominant risk-significant configurations. The licensee’s measures to avoid high risk-significant plant configurations are consistent with staff’s Tier 2 guidance.

Configuration Risk Management Program (Tier 3)

A CRMP is to provide a proceduralized, risk-informed assessment of the plant so as to manage the risk associated with equipment inoperability and, in order to be applicable to risk-informing TSs, it must be consistent with associated evaluation processes and acceptance criteria. The CRMP is to utilize at least a Level 1, at-power, internal events PRA model and is expected to take into consideration qualitative factors that cannot be incorporated into the quantitative model (such as those discussed above in connection with Tier 2). As noted earlier in this evaluation, licensees typically use the risk management procedures developed for implementation of the Maintenance Rule to manage risks associated with TS LCO AOT changes. RBS does this through its Maintenance Rule implementation procedure, ADM-0096.

As input to the procedure, maintenance is normally assessed from a probabilistic standpoint using the EOOS system, the RBS computerized on-line risk monitor. Qualitative assessments are incorporated as needed. The EOOS system measures nuclear safety only with respect to core damage; containment failure and radiological dose to the public are not considered. The EOOS system calculates CDF based on specific equipment being OOS and converts CDF into a plant safety index scale and color code. Risk management actions are associated with the color code. A table showing this relationship is presented below:

CDF Range	CODE	Level of Risk Management Action
> 6.8E-04/yr	Red	Unacceptable Risk - Should not be entered voluntarily. If entered involuntarily, timely actions should be taken to restore equipment or put the plant in a safer condition.
6.8E-04 to 1.3E-04/yr	Orange	High Risk - Contingency plans should be developed if entered voluntarily. Maintenance should be considered for continuous coverage. If involuntary entry, attempt to restore equipment to reduce risk to the Yellow range.
1.3E-04 to 6.2E-06/yr	Yellow	Acceptable Risk - Ensure that subsequent maintenance activities do not increase risk to a higher risk level color (i.e., orange or red).
< 6.2E-06/yr	Green	Minimal Risk - Normal work controls are sufficient.

According to RG 1.177, a Tier 3 assessment is acceptable if a risk-informed plant configuration control program has been implemented together with procedures to utilize, maintain, and control such a program. The licensee's administrative procedure ADM-0096 is consistent with the staff's Tier 3 guidance.

3.3 Probabilistic Conclusion

As the frequency and length of on-line maintenance outages for risk significant equipment increases, the probability of overlap (both inadvertent and planned) increases, with an associated increase in risk. In view of the uncertainty concerning the risk status of the plant when an LCO is entered, and the length of time it is appropriate for the plant to remain at that level of elevated risk, the overall adequacy of risk management capabilities when applied to all TS maintenance takes on added significance.

As this evaluation points out, consistent with NRC guidance in RG 1.177, RBS has provided (1) an estimate of the minimum ICCDP for the extension (i.e., for the case where no other risk-significant equipment is OOS), that meets the NRC staff standard for a small change in risk; (2) a list of risk-significant equipment, which the licensee would require to be in service prior to planned EDG maintenance; and (3) a description of the RBS risk management program, which meets the essential characteristics for a CRMP. Hence, from a risk perspective, the licensee's proposed TS LCO AOT change is acceptable to the staff.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Louisiana State official was notified of the proposed issuance of the amendment. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (66 FR 64292, published December 12, 2002). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

6.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

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