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September 24, 2001

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D. C. 20555

Subject: River Bend Station
Docket No. 50-458
License No. NPF-47
License Amendment Request (LAR) 2001-027, Emergency Diesel Generator Extended Allowed Outage Time.

File Nos.: G9.5, G9.42

RBEXEC-01-039
RBF1-01-0180
RBG-45832

Gentlemen:

Attached for your review and approval are proposed changes to River Bend Technical Specifications (TS) 3.8.1, "AC Sources – Operating." These changes are requested to extend the allowed outage time (AOT) for a Division I or Division II Emergency Diesel Generator (EDG) from 72 hours to 14 days. These proposed changes are intended to provide flexibility in scheduling EDG maintenance activities, reduce refueling outage duration, and improve EDG availability during plant shutdowns. The NRC has approved similar requests for several other plants. This request is similar to the Perry Nuclear Power Plant and Clinton Power Station applications. Entergy has evaluated the proposed changes using traditional engineering analyses as well as a risk-informed approach as set forth in RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications."

The proposed changes have 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. New commitments are made to support the proposed changes and are identified in Attachment 1.

A001

The information supporting the proposed changes are subdivided in the attachments as follows:

Attachment 1: Commitment Identification Form
Attachment 2: Proposed Technical Specification and Respective Safety Analyses
Attachment 3: RBS PSA Peer Review Certification Information
Attachment 4: Description of RBS PSA Model Changes
Attachment 5: Tier 1 Diesel Generator PSA Study Results
Attachment 6: Markup of Current TS Pages
Attachment 7: Markup of Current Bases Pages (for information only).

Entergy requests the effective date for this TS change to be within 60 days of approval. Although this request is neither exigent nor emergent, your prompt review is requested. Entergy plans to use this amendment to perform preventive maintenance activities in the spring of 2002. The spring schedule is preferred because the potential for offsite electrical supply perturbations are generally less than during the summer and hurricane seasons.

I declare under penalty of perjury that the foregoing is true and correct. Executed on September 24, 2001.

Very truly yours,

Randall K. Edington

RKE/RJK/RWB
Attachments (7)

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Attachment 1
Commitment Identification Form

Commitment	**One-Time Action***	**Continuing Compliance***
Additional contingencies, which will be administratively controlled, include: 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. High pressure injection systems (HPCS and RCIC) will not be taken out of service for planned maintenance while EDG A (Division I) or EDG B (Division II) is out of service for extended maintenance.		X
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 a SBO when immediate recovery of Division I and Division 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.	X	

*Check only one.

ATTACHMENT 2

TO

LETTER NO. RBG 45832

PROPOSED TECHNICAL SPECIFICATION

AND

RESPECTIVE SAFETY ANALYSES

IN THE MATTTER OF AMENDING

LICENSE NO. NPF-47

ENTERGY OPERATIONS, INC.

DOCKET NO. 50-458

1.0 DESCRIPTION OF PROPOSED CHANGES

Entergy proposes by this request to amend Operating License NFP-47 for River Bend Station. The proposed change would revise Appendix A, "Technical Specifications" to permit a longer allowed outage time (AOT) for the Division 1 and Division 2 Emergency Diesel Generators (EDGs). This would allow greater flexibility and more efficient planning of EDG maintenance and testing activities during plant operation. This, in turn, can reduce the number of EDG outages while improving overall availability. The changes would also reduce plant refueling outage duration and improve EDG availability during refueling outages.

Currently, RBS TS 3.8.1 requires an inoperable EDG to be restored to OPERABLE status within 72 hours (REQUIRED ACTION B.4). 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 cannot be met, the plant must be placed in Hot Shutdown within 12 hours and Cold Shutdown within 36 hours. Entergy proposes to revise the COMPLETION TIME associated with REQUIRED ACTION B.4 to allow an AOT of 14 days for an inoperable Division 1 or Division 2 EDG. In addition, the COMPLETION TIMES of 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 extended AOT would typically be used for voluntary planned maintenance or inspections but can also be used for corrective maintenance. Entergy intends to limit use of the extended AOT for voluntary planned maintenance or inspections to once within an operating cycle (18 months) for each EDG (Division I and Division II). Any additional EDG unavailability is monitored and evaluated in relationship to Maintenance Rule goals to ensure that EDG outage times do not degrade operational safety over time.

In summary, the TS AOT for a Division 1 or Division 2 EDG during Modes 1, 2, or 3 would be increased from 72 hours to 14 days. 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. Marked-up pages indicating the proposed changes are provided in Attachment 6.

Respective changes will also be made to the TS Bases in accordance with the Bases control program of TS 5.5.11. The Bases will reflect the risk-informed nature of the extended AOT and note that use of the extended AOT for voluntary planned maintenance or inspections should be limited to once within an operating cycle (18 months) for each EDG (Division I and Division II). These changes are provided in Attachment 7 for your information.

2.0 BACKGROUND

The RBS Class 1E AC electrical power sources consist of two offsite power sources and three onsite standby power sources (diesel generators (EDGs)). 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 ESF 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 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 USAR Chapter 8. Additional information regarding grid stability was provided to the NRC staff in letter RBG-45293 from R. J. King of Entergy to the USNRC dated April 3, 2000, in support of the RBS power uprate amendment. The stability analysis showed continued stable performance at the new RBS power output level.

The onsite standby power source for each ESF bus is a dedicated EDG that starts automatically on loss of coolant accident (LOCA) signal or on 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 accordance with GDC 17 and 18.

The current RBS TS 3.8.1 requires that if a EDG is declared inoperable for any reason, the EDG must be restored to an OPERABLE status within 72 hours or the plant must be placed in at least hot shutdown within 12 hours and in cold shutdown within 36 hours. An exception is allowed for the Division III EDG. A note in TS 3.8.1 allows the HPCS system to be declared inoperable in lieu of declaring the Division III EDG inoperable. This exception allows the Division III to be inoperable for up to an additional 14 days provided that the RCIC system is OPERABLE (see TS 3.5.1). Therefore the AOT extensions being requested relate only to the Division I and Division II EDGs.

The requested changes are sought in order to provide needed flexibility in the performance of corrective and preventive maintenance during power operation. In addition, the adoption of the proposed AOT extensions reduces the risk of unscheduled plant shutdowns. In general, risks incurred by unexpected plant shutdowns can be comparable to and even may exceed those associated with continued power operation.

Attachment 5 includes an evaluation which confirms 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 changes would also minimize the potential for Notice of Enforcement Discretion (NOED) requests.

The NRC has approved similar requests for several other plants. This request is similar to the Perry Nuclear Power Plant application (TAC NO. MA3537) since both Perry and RBS are BWR6 plants and have the capability of using the Division III HPCS EDG as an alternate AC power source through a cross-tie to the Division I or Division II ESF buses. Another similar request, submitted by AmerGen for the Clinton Power Station, is currently under NRC review (TAC NO. MB0861).

3.0 BASIS FOR PROPOSED CHANGE

3.1 REGULATORY EVALUATION

The proposed changes have been evaluated to determine whether applicable regulations and requirements continue to be met. The conformance discussion for General Design Criteria (GDC) is provided in Chapter 8 as well as in Section 3.1 of the RBS USAR. The conformance discussion for the Branch Technical Positions (BTPs) applicable to electrical power systems is referenced in USAR Table 8.1-3. Entergy has determined that the 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 USAR.

10CFR50.36 requires a licensee's TS to establish limiting conditions for operations, which include allowed outage times for equipment required for safe operation of the facility. Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources" prescribes a maximum TS AOT of 72 hours for an inoperable AC power source (consistent with the current TS). The RG also states that the time limits are explicitly for corrective maintenance activities and do not include preventive maintenance activities which require the incapacitation of any required electric power source. If the proposed changes are approved, RBS will continue to conform to RG 1.93 with the exception that the TS AOT for an inoperable EDG may be increased from 72 hours to 14 days and may be used for EDG preventive maintenance activities rather than for corrective maintenance activities only. This deviation is justified based on the technical analysis provided in Section 3.2.

3.2 TECHNICAL ANALYSIS

Entergy has evaluated the proposed changes using traditional engineering analyses as well as a risk-informed approach as set forth in RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications." RG 1.177

prescribes an acceptable approach for requesting TS changes that go beyond current staff positions, especially for those such as relaxations to AOTs or surveillance test intervals. These evaluations and conclusions are also consistent with the guidance of RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis".

3.2.1 ENGINEERING CONSIDERATIONS

Defense-in-Depth

The impact of the proposed change was evaluated and determined to be consistent with defense-in-depth philosophy. The limited unavailability of a single power source caused by entry into a TS action does not significantly change the defense-in-depth balance among the principles of prevention of core damage, prevention of containment failure, or consequence mitigation.

The defense-in-depth philosophy requires multiple means or barriers to be in place to accomplish safety functions and prevent the release of radioactive material. RBS is designed and operated consistent with the defense-in-depth philosophy. The ESF equipment required to mitigate the consequences of postulated accidents consists of three independent divisions. 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 station has diverse AC power sources available to the three divisions to cope with the loss of the preferred power source.

In addition, the Division III High Pressure Core Spray (HPCS) EDG can be cross-connected to either the Division I or the Division II AC buses to provide an alternate AC power source in the event of a station blackout. The operators can restore power to those components by closing the breakers between the Division III EDG and the 4.16 KV bus. Like other BWR6s, RBS will develop a procedure to align the Division III EDG to the Division I or II bus. The procedure will be issued prior to implementation of the EDG AOT extension. Additionally, a 200 kW, 480 VAC, 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 charger, the SBO diesel can then provide power to either the Division I or II 125 VDC batteries under station blackout conditions. The SBO diesel generator is only credited as a backup to the safety related DC batteries during station blackout events.

Since the proposed AOT change allows some Division I and Division II EDG work to be performed on-line, the availability of the EDGs during shutdowns should be increased, thus providing increased defense-in-depth during outages. Some EDG maintenance may still be performed during a refueling outage, but to a lessor extent.

The proposed AOT extension does not introduce any new common cause failure mechanisms and protection against common cause failure modes previously considered is not compromised. The proposed changes do not degrade the independence of any physical barriers.

Defenses against human errors are maintained with the proposed TS changes. Qualified personnel will continue to perform EDG maintenance and overhauls whether they are performed on-line or during shutdowns. As is the current practice with an inoperable EDG, 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 Loss Of Offsite Power (LOOP) or SBO. The procedure for alignment of the Division III EDG to the Division I or II bus is new but will only be used in the unlikely event of a SBO when immediate recovery of Division I and Division 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.

Appropriate restrictions and compensatory measures will be established to ensure that system redundancy, independence, and diversity are maintained commensurate with the risk associated with the extended AOT. These include current TS requirements as well as administrative controls.

The ACTIONS of TS 3.8.1 for an inoperable EDG provide assurance that sufficient power sources remain and that a LOOP would not result in a complete loss of safety function by:

- verifying offsite power availability within one hour and once every 8 hours thereafter (ACTION B.1),
- ensuring that redundant required features that are associated with a division redundant to the inoperable EDG are not concurrently inoperable (ACTION B.2), and
- verifying the operability of the remaining EDG by ensuring that a common cause failure does not exist or by increased testing (ACTIONS B.3.1 or B.3.2).

In addition to the above TS conditions, Entergy will implement other restrictions and compensatory measures through administrative procedures to limit the potential risk associated with the extended AOT. These include:

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 maintenance period.

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. High pressure injection systems (HPCS and RCIC) will not be taken out of service for planned maintenance while EDG A (Division I) or EDG B (Division II) is out of service for extended maintenance.

Safety Margins

The proposed extended AOT is not in conflict with any of the approved codes and standards applicable to the onsite AC power sources other than RG 1.93 as discussed previously. An extension of the RG 1.93 recommended 72 hour AOT to 14 days is not unreasonable and has been approved for several other licensees. It should be noted that EDG reliability and availability are monitored and evaluated in relationship to Maintenance Rule goals to ensure that EDG outage times do not degrade operational safety over time. Additionally, unavailability is monitored through the performance indicators of the Regulatory Oversight Process.

The proposed AOT change does not affect any of the assumptions or inputs to the safety analyses of the FSAR. Assuming there are no additional failures of redundant equipment during the time that the EDG is removed from service, the intended safety functions would still be met.

Additionally, the proposed changes do not erode the decrease in severe accident risk achieved with the issuance of the Station Blackout (SBO) Rule. The SBO Rule, promulgated as 10CFR50.63 "Loss of All Alternating Current Power," requires that a facility be able to withstand a SBO for a specified duration and recover. The extended EDG AOT would not impact the SBO coping analysis since the Reactor Core Isolation Cooling (RCIC) System is designed to assure that sufficient water inventory is maintained in RPV to permit adequate core cooling to take place. RBS is classified as a four-hour coping plant with 0.95 EDG reliability (see UFSAR Appendix 15C). The assumptions used in the SBO analysis regarding reliability of the EDGs are unaffected by the proposed TS changes since preventive maintenance and testing will continue to be performed to maintain reliability assumptions.

3.2.2 EVALUATION OF RISK IMPACT

To assess the overall impact on plant safety, a probabilistic safety analysis (PSA) was performed consistent with the guidance pertaining to risk-informed criteria specified in Regulatory Guide 1.177, "An Approach for Plant-Specific Risk-Informed Decisionmaking: Technical Specifications." The change in average Core Damage Frequency (CDF) and average Large Early Release Frequency (LERF) resulting from the increased Allowed Outage Time (AOT) for the Division I and Division II emergency diesel generators (EDGs) was evaluated. This evaluation included consideration of the Maintenance Rule (a)(4) Program established pursuant to 10CFR50.65 to control performance of other potentially high risk tasks during an EDG outage and consideration of specific compensatory measures to minimize risk. All of these elements were included in a risk evaluation performed using the three-tiered approach suggested in RG 1.177, as follows:

Tier 1 - PSA Capability and Insights,
Tier 2 - Avoidance of Risk-Significant Plant Configurations, and
Tier 3 - Risk-Informed Configuration Risk Management.

Evaluations per each of these tiers are provided in this section. Presented first, however, is background information related to the development, certification and application of the PSA model in place for RBS.

RBS PSA Model-Development

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.[1] Attachment 3 provides more details, including a summary of the PSA Certification Team members' qualifications and key findings. The RBS PSA has also benefited from subsequent plant reviews of the other BWR-6 plants.

The RBS At-Power PSA has been revised twice since the PSA Peer review, most recently in January 2001 in conjunction with the RBS 5% power uprate. Significant operational and hardware changes as they affect AC power supplies and the evaluation of LOOP events were incorporated in the model. Attachment 4 provides details of the changes made in PSA Model Revision 2D and PSA Model Revision 3. Both revisions were performed in accordance with the process defined at RBS for updating and maintaining the PSA, as discussed later.

The Revision 3 At-Power PSA model was further modified in three ways to support this submittal. This revision is referred to as Revision 3A. First, the operator recovery actions for offsite power recovery were enhanced by using convolution to determine the recovery frequency. Second, a recovery action to align the Division III EDG to the Division I or Division II bus was added. Finally, a human reliability analysis (HRA) for an operator contingency action to manually open an air-operated valve during a station blackout event was added. These changes are discussed in detail in Attachment 4 along with a summary of the updated risk information.

[1] The BWROG PSA Peer Review Certification program does not specifically evaluate the PSA models for a particular application such as an EDG AOT extension. However, the grading process for the Certification Program is intended to indicate the types of PSA applications for which the attributes of the PSA are suitable. Those certification elements receiving Grade 3 are deemed to be suitable for types of applications such as single TS actions if supported by deterministic evaluations. Not all areas of the PSA have to be assigned Grade 3 or greater to be suitable for TS changes. An important aspect of the certification process is the development of Facts & Observations (F&Os) that describe the issues relevant to particular sub-elements of the PSA. The impact of these issues on the particular PSA application being developed should be understood and addressed as appropriate.

The RBS Shutdown PSA model was initially developed for RBS refueling outage (RF) 7 in 1997. EPRI Report TR-113084, "Development of Shutdown Probabilistic Safety Analysis (PSA)/Shutdown Equipment Out of Service for River Bend Station," provides a good overview of the development of the RBS Shutdown PSA. Shutdown PSA model Revision 3 was completed in August 2001 to support RF-10. The Shutdown PSA project is intended to provide a PSA model comparable in scope to the Level 1 PSA model to address outage risk assessment. The Shutdown PSA models are developed for use in the Equipment Out of Service (EOOS) Monitor for outage risk assessment. It provides an in-depth assessment of outage risk.

The RBS Level 2 model was revised in August 2000. The RBS base LERF is based on PSA Level 1 Rev. 2D. The Level 2 analysis was reviewed and it has been determined that the revision to the Level 1 analysis does not change insights provided by the current Level 2 analysis. This does not imply that the large early release frequency (LERF) or containment failure probabilities are unaffected. Given that the starting point for the Level 2 analysis is core damage, a change in core damage frequency (CDF) inherently changes Level 2 analysis results. With the current Level 2 analysis, only a hydrogen burn or a failure of the containment isolation system resulting in a leakage path of one square foot or larger contribute to LERF. This is unchanged by the Level 1 revision. The Level 1 revision does change the probability of a LOOP or SBO leading to core damage. The Level 2 analysis was qualitatively reevaluated by reviewing the event trees and applying engineering judgement. This evaluation also included the removal of the IFTS blind flange (Reference RBG-45562 dated November 29, 2000). Since Revision 3, the Level 1 PSA model was revised to include convolution and several operator recovery actions and to evaluate the diesel generator allowed outage time (AOT) extension (Revision 3A). The Level 2 analysis was again qualitatively reevaluated by reviewing the event trees and using some engineering judgement to determine a LERF for the current PSA model. Results are presented in Attachment 5.

RBS PSA Model Maintenance

Updating and maintenance of the PSA is controlled under the following documents:

- Central Design Engineering Manual procedure CDE-P-05.01-00, "Probabilistic Safety Assessment (PSA) Model Maintenance"
- Engineering Department Procedure, EDP-AN-01, "Control Of System Notebooks for Probabilistic Safety Assessment"
- Engineering Department Guide EDG-AN-003, "Content And Review of System Notebooks for the Level 1 Probabilistic Safety Assessment (PSA) and Control of PSA Information".

CDE-P-05.01-00 requires a monthly review by the PSA Engineer of procedure changes and calculations revised in the preceding month that could impact the PSA model. As part of the current engineering request process there are review checklists used to identify the need to have particular engineering groups review the design change being developed. Review by the PSA group is required if it affects systems modeled in the PSA. If a PSA review is required, a PSA analyst reviews the design change to determine if it would impact the current PSA model.

As part of the monthly review required by CDE-P-05.01-00, each change determined to impact the PSA model is graded to determine the appropriate schedule for implementation. If possible, the change is reviewed in a risk analysis that evaluates the risk implications of the change before implementation. If that is not possible, engineering judgement is used.

The PSA model change grading is A, B, C, or D based on the following plant certification comment grades. The scale below summarizes these grades.

GRADE	DEFINITION
A	Extremely important and necessary to address to assure the technical adequacy of the PSA, the quality of the PSA, or the quality of the PSA update process.
B	Important and necessary to address, but may be deferred until the next PSA update.
C	Considered desirable to maintain maximum flexibility in PSA applications and consistency in the industry, but not likely to significantly affect results or conclusions.
D	Editorial or minor technical item, left to the discretion of the PSA Site Lead, PSA Supervisor, or Site Safety Analysis Manager.

Once per month, the site PSA Engineer provides the PSA Supervisor a report on the status of the PSA model, primarily containing an assessment of the A and B grade model change requests (MCRs) on the PSA model. An interim PSA model update is scheduled as soon as possible after a MCR is graded A. The PSA Supervisor reviews the monthly PSA status report and initiates discussions with the site PSA Engineer and site Safety Analysis Manager to determine the need for an interim update for reasons other than a grade A MCR. An interim PSA model update is scheduled as soon as possible after the decision is made that a model revision is necessary. Periodic PSA model updates are performed at least every two years, or as data dictates.

Once the determination for a PSA update is made, EDP-AN-01, "Control of System Notebooks for Probabilistic Safety Assessment," and EDG-AN-003, "Content And Review of System Notebooks for the Level 1 Probabilistic Safety Assessment (PSA) and Control of PSA Information," provides guidance on the model update process. PSA system notebooks have been developed which contain key model assumptions used in the development of the fault tree models. During a model update these notebooks are reviewed to determine whether the system has changed in a way that requires a system model change. This serves as a second check that relevant design changes are incorporated in the model.

Application of the RBS PSA

RBS PSA Model Revision 3A was used to determine changes in risk from removing the EDGs from service for maintenance. The risk measures used are Core Damage Frequency and Large Early Release Frequency. A description of the risk management control program is included in the Tier 3 section.

The PSA model is used by Scheduling and Operations personnel throughout the process of planning and implementing work. This is implemented through the use of a "Plant Safety Index" and color codes described in RBS 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 results obtained from the PSA model are used as part of a blended approach along with other inputs such as TS requirements and operator system knowledge to determine the final work schedule.

The PSA addresses internal events at full power and shutdown. Other risk sources and operating modes are discussed in Attachment 5. A special effort was made to ensure that those aspects of the PSA that are potentially sensitive to changes in EDG maintenance unavailability are adequate to evaluate the risk impacts of the increased allowed outage times for the EDGs.

For use of the PSA to support changes to the Technical Specifications, the guidance of RG 1.177, "An Approach for Plant –Specific, Risk Informed Decisionmaking: Technical Specifications," is utilized. With regard to the evaluation recently performed to support extension of the EDG AOT, RBS is confident that the results of the risk evaluation (described more fully in Attachment 5) are technically sound and consistent with the expectations for PSA quality set forth in RG 1.177. The scope, level of detail, and quality of the PSA is sufficient to support a technically defensible and realistic evaluation of the risk change from this proposed AOT extension.

Tier 1: PSA Capability and Insights

As noted previously, risk-informed support for the proposed changes to the EDG AOT (for either Division 1 or Division 2) is based on PSA calculations performed to quantify the change in average CDF and average LERF resulting from the increased AOT. To determine the effect of the proposed changes with respect to plant risk, the guidance provided in RG 1.177 was used.

An evaluation was performed based on the assumption that the full extended AOT (i.e., 14 days) would be applied once per EDG per refueling cycle. The cycle time is based on the current 18-month fuel cycle (allowing for planned and unplanned plant outage time) for a net total cycle length of 475 operating days. It should be noted that EDG reliability and availability are monitored and evaluated in relationship to Maintenance Rule goals to ensure that EDG outage times do not degrade operational safety over time.

The incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) were computed per their definitions in RG 1.177. The results of the risk evaluation, including the computed ICCDP and ICLERP, are presented in Attachment 5. The results of the risk evaluation were compared with risk significance criteria from RG 1.174 for changes in the annual average CDF and LERF and from RG 1.177 for ICCDP and ICLERP. The ICCDP and ICLERP evaluation was based on the Division I emergency diesel generator (EDG A), which provides the limiting values for this risk metric. The values for the ICCDP and the ICLERP demonstrate that the proposed EDG AOT change has only a small quantitative impact on plant risk.

The results of the risk evaluation are presented in the table below.

Risk Metric	Significance Criterion	RBS Results
ΔCDF_{AVG}	<1.0E-06/yr	4.87E-7/yr
ICCDP	<5.0E-07	3.88E-7
$\Delta LERF_{AVG}$	<1.0E-07/yr	2.14E-9/yr
ICLERP	<5.0E-08	1.40E-9

Tier 2: Avoidance of Risk-Significant Plant Configurations

A Configuration Risk Management Program (CRMP) is in place at RBS in accordance with RBS commitments for compliance with 10CFR50.65, particularly with respect to paragraph (a)(4) of that regulatory requirement. The program provides assurance that risk-significant plant equipment configurations are precluded or minimized when plant equipment is removed from service. For a plant EDG removed from service, increases in risk posed by potential combinations of equipment out of service will be managed in accordance with the CRMP program. Additional contingencies, which will be administratively controlled, include:

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. High pressure injection systems (HPCS and RCIC) will not be taken out of service for planned maintenance while EDG A (Division I) or EDG B (Division II) is out of service 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. Cutsets were generated for EDG A and B out of service individually. These cutsets were reviewed for insights as to which systems or actions are most critical to reducing plant risk while an EDG is out of service for extended maintenance. Attachment 4 provides the initiating event frequency distribution and top eight cutsets with EDG A or EDG B out of service. Also, the Equipment Out of Service (EOOS) program was used to generate a list of in-service equipment that would be more important as a result of EDG A or B being out of service.

For EDG A, the primary systems included:

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

For EDG B, the primary systems included:

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

Procedural and Technical Specification controls are already in place which will ensure that these systems are not removed from service while an EDG is out of service for extended maintenance. Any of these systems would result in an EOOS color code of "Red." This level of risk would not be entered voluntarily. Note that a "Red" risk condition typically overlaps conditions prohibited by Technical Specifications or conditions requiring entry into a Technical Specification Action. General Manager / Designee notification is required upon entering a "Red" condition from emergent activities. If an entry into a "Red" condition occurs (e.g., due to equipment failures), then steps would be taken to restore any equipment out for testing or maintenance that could improve the plant safety index (PSI). Timely actions would be taken to reduce plant risk by either restoring inoperable or unavailable equipment or to put the plant in a safer condition (e.g., reduce power or shutdown), taking into account any risk associated with the transient required to achieve the safer state.

Tier 3: Risk-Informed Configuration Risk Management Program

Consistent with 10CFR50.65(a)(4), and as indicated above, RBS has developed a program that ensures that the risk impact of out-of-service equipment is appropriately evaluated prior to performing a maintenance activity. The procedures that govern this process are RBS 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 RBS On-Line Maintenance Guide ensures that risk from planned maintenance is evaluated and that maintenance activities are scheduled appropriately. This program requires an integrated review (i.e., both probabilistic and deterministic) to identify risk-significant plant equipment outage configurations in a timely manner both during the work management process and for emergent conditions during normal plant operation. Appropriate consideration is given to equipment unavailability, operational activities like testing or load dispatching, and weather conditions. This program includes provisions for performing a configuration-dependent assessment of the overall impact on risk of proposed plant configurations prior to, and during, the performance of maintenance activities that remove equipment from service. Risk is re-assessed if an equipment failure/malfunction or emergent condition produces a plant configuration that has not been previously assessed.

For planned maintenance activities, an assessment of the risk of the activities on plant safety is performed prior to the scheduled work. The assessment includes the following considerations:

- Maintenance activities that affect redundant and diverse structures, systems, and components (SSCs) that provide backup for the same function are minimized.

- The potential for planned activities to cause a plant transient are reviewed and work on SSCs that would be required to mitigate the transient are avoided.

- Work is not scheduled that is likely to exceed a TS or Technical Requirements Manual (i.e., a licensee controlled document containing requirements removed from the TS as part of conversion to the Improved Standard TS) completion time requiring a plant shutdown.

- For Maintenance Rule Program High Risk Significant SSCs, the impact of the planned activity on the unavailability performance criteria is evaluated.

- As a final check, a quantitative risk assessment is performed to ensure that the activity does not pose any unacceptable risk. This evaluation is performed using the Level 1 PSA model. The results of the risk assessment are classified by a color code based on the increased risk of the activity. These color code classifications are described in the following table.

Risk Color Code Classification

Color	*Level of Risk*	*Break Points*	*Plant Impact and Required Action*
Green	Minimal Risk	Lower limit corresponds to two times zero maintenance CDF.	Normal work controls are sufficient.
Yellow	Acceptable Risk	Lower limit corresponds to one train of standby service water (SWP) out of service (train A).	Measures should be taken to ensure that subsequent maintenance activities do not increase risk to a higher risk level color (orange or red condition).
Orange	High-Risk	Lower limit corresponds to SWP train A and the train B diesel generator out of service OR NEI 93-01 limit[2], whichever is lower.	It is anticipated that entry into an "Orange" region will be relatively infrequent. While infrequent entry into an "Orange" condition is acceptable, written guidance/contingency plans should be developed if this condition will be entered voluntarily. General Manager / Designee approval for voluntary entry, or notification upon emergent entry is required. FRC review and approval is required for a preplanned "Orange" condition. Maintenance causing an "Orange" condition should be considered for continuous coverage. IF this condition is a result of emergent work, THEN steps should be taken to restore any equipment out for testing that could improve the Plant Safety index.
(Continued on next page)			

[2] NEI 93-01 Section 11.3.7.2 explains that the EPRI PSA Applications Guide (EPRI TR-105396), section 4.2.3, includes guidance for evaluation of temporary risk increases. The guidance is as follows: The configuration-specific CDF should be considered in evaluating the risk impact of the planned maintenance configuration. Maintenance configurations with a configuration-specific CDF in excess of 10^{-3}/year should be carefully considered before voluntarily entering such conditions. If such conditions are entered, it should be for very short periods of time and only with a clear detailed understanding of which events cause the risk level.

Continued- **Risk Color Code Classification**			
Color	***Level of Risk***	***Break Points***	***Plant Impact and Required Action***
Red	Unacceptable Risk	Risk greater than SWP train A and diesel generator train B out of service.	This level of risk should not be entered voluntarily. Note that a "Red" risk condition typically overlaps conditions prohibited by Technical Specifications or conditions requiring entry into a Technical Specification Action. General Manager / Designee notification is required upon entering a "Red" condition from emergent activities. IF an entry into a "Red" condition occurs (e.g., due to equipment failures), THEN steps should be taken to restore any equipment out for testing that could improve the plant PSI index. Timely actions should be taken to reduce plant risk by either restoring inoperable or unavailable equipment or to put the plant in a safer condition (e.g., reduce power or shutdown), taking into account any risk associated with the transient required to achieve the safer state.

Emergent work is reviewed by Work Management and Operations to ensure that it does not invalidate the assumptions made during the schedule development process. Prior to starting any work, the work scope and schedule are critically reviewed to assure that nuclear safety and plant operations are consistent with the expectations of management.

The probability of plant fire events is not assessed for distinct plant activities such as EDG maintenance. However, the RBS Fire Protection Program significantly minimizes fire risk through various design features and administrative controls that address fire prevention as well as mitigation. River Bend Nuclear Procedure RBNP-038, Site Fire Protection Program, prescribes the fire prevention and fire protection policies necessary to implement the approved Fire Protection Program. The program assures that an adequate balance in the defense-in-depth concepts are maintained to minimize both the probability and consequences of damage due to fire throughout the River Bend site.

The Fire Protection Program uses a three tiered approach:

1. The application of administrative controls to prevent fires from starting.
2. The use of active engineered design features to detect and suppress fires, limiting damage consequences of fires that do start.
3. The use of passive barriers in combination with the design of plant safety systems such that fires will not prevent essential plant safety functions from achieving and maintaining safe shutdown.

Fire prevention is accomplished through the following procedures:

FPP-0030, Storage of Combustibles, establishes requirements for the safe storage of combustibles in safety related areas and is used as a recommended practice in other areas of the plant.

FPP-0040, Transient Combustibles, establishes controls for transient combustibles associated with maintenance and modification activities in the Power Block.

FPP-0050, Handling of Flammable Liquids and Gases, establishes requirements for the safe handling of flammable liquids and gases.

FPP-0060, Hot Work Permit, establishes the requirements for the safe storage of combustibles in safety related areas and is used as a recommended practice in other areas of the plant.

FPP-0070, Duties of Fire Watch, describes the responsibilities and duties of persons associated with assigning, documenting, and performing fire watch duties.

As with current maintenance practices, these procedures would be used, as applicable, during the extended EDG maintenance to minimize the risk from fire.

4.0 IMPLEMENTATION AND MONITORING PROGRAM

To ensure the proposed extension of the EDG AOT does not degrade operational safety over time, should equipment not meet its performance criteria, an evaluation is required as part of the Maintenance Rule (MR) (i.e., 10 CFR 50.65).

The reliability and availability of the affected EDGs at RBS are monitored under the Maintenance Rule Program as implemented by Procedure DC-121, "Maintenance Rule." If the pre-established reliability or availability performance criteria are exceeded for the

EDGs, consideration must be given to 10 CFR 50.65 (a)(1) actions, including increased management attention and goal setting in order to restore EDG performance (i.e., reliability and availability) to an acceptable level. The performance criteria are risk informed and, therefore, are a means to manage the overall risk profile of the plant. An accumulation of large core damage probabilities over time is precluded by the performance criteria.

In practice, the actual out-of-service time for the EDGs is minimized to ensure that MR reliability and availability performance criteria for these components are not exceeded. It should be noted that the EDG availability used in the PSA analysis to calculate the ΔCDF_{avg} value for a 14-day AOT is conservative compared to the EDG system MR goals, actual past performance of the EDGs at the plant, and expected availability following implementation of the proposed increased EDG AOT. The latter is true because a full 14 days of unavailability per cycle is not anticipated.

The EDGs are all currently in the 10 CFR 50.65 (a)(2) MR category (i.e., the EDGs are meeting established performance goals). Performance of the EDG on-line maintenance is not anticipated to result in exceeding the current established MR criteria for EDGs.

Pursuant to 10 CFR 50.65 (a)(3), EDG reliability and availability is monitored and periodically evaluated in relationship to the MR goals. The RBS EDG availability goal is 97.5%. The current cycle (18 month) EDG availability is approximately 98.5% including fault exposure and 99% excluding fault exposure. The MR performance goal for reliability is no more than one maintenance preventable functional failure (MPFF) per division in a rolling 18-month period. In the last 18 months, the EDGs have not failed to start in any of the 82 demands. The Division II EDG has had two functional failures in the past 18 months. Only one of these failures was a MPFF.

The MR Program provides a process to identify and correct adverse trends to ensure the TS Allowed Outage Time does not degrade operational safety over time. Compliance with the MR not only optimizes reliability and availability of important equipment, it also results in management of the risk when equipment is taken out of service for testing or maintenance per 10CFR50.65 (a)(4).

5.0 CONCLUSION

The proposed extension of the Division I and Division II EDG AOT is based upon both a deterministic evaluation and a risk-informed assessment. The deterministic evaluation determined that an extended allowed outage time for the Division I and Division II EDGs is consistent with the defense-in-depth philosophy and that sufficient safety margins are maintained. The risk-informed assessment concluded that the increase in plant risk is small and consistent with the USNRC "Safety Goals for the Operations of Nuclear Power Plants; Policy Statement," Federal Register, Vol.5 1, p. 30028 (51 FR 30028), August 4, 1986, as further described by NRC Regulatory Guide 1.177. Together these analyses provide high assurance of the capability to provide power to the ESF buses during the proposed extension of the Division I and Division II EDG AOTs.

The proposed changes are consistent with NRC policy and will continue to provide adequate protection of public health. The changes advance the objectives of the NRC's Probabilistic Risk Assessment (PRA) Policy Statement, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Volume 60, p. 42622, August 16, 1995, for enhanced decision-making and results in a more efficient use of resources and reduction of unnecessary burden.

Maintenance during power operation should improve overall EDG availability which, in turn, should result in reducing shutdown risk by increasing the availability of emergency power during refueling outages.

6.0 DETERMINATION OF NO SIGNIFICANT HAZARDS CONSIDERATIONS

Entergy Operations, Inc. is proposing that the River Bend Operating License be amended to allow the extension of the Completion Time for the Division I and Division II Emergency Diesel Generators (EDGs) from 72 hours to 14 days to allow on-line maintenance to be performed.

An evaluation of the proposed change has been performed in accordance with 10CFR50.91(a)(1) regarding no significant hazards considerations using the standards in 10CFR50.92(c). A discussion of these standards as they relate to this amendment request follows:

1. **Will operation of the facility in accordance with this proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?**

   The proposed Technical Specification (TS) changes do not affect the design, operational characteristics, function, or reliability of the EDGs. The EDGs are not the initiators of previously evaluated accidents. The EDGs are designed to mitigate the consequences of previously evaluated accidents including a loss of offsite power. Extending the allowed outage time (AOT) for a single EDG would not significantly affect the previously evaluated accidents since the remaining EDGs supporting the redundant ESF systems would continue to perform the accident mitigating functions as designed.

The duration of a TS AOT is determined considering that there is a minimal possibility that an accident will occur while a component is removed from service. A risk-informed assessment was performed which concluded that the increase in plant risk is small and consistent with the USNRC "Safety Goals for the Operations of Nuclear Power Plants; Policy Statement," Federal Register, Vol.5 1, p. 30028 (51 FR 30028), August 4, 1986, as further described by NRC Regulatory Guide 1.177.

The current TS requirements establish controls to ensure that redundant systems relying on the remaining EDGs are Operable. In addition to these requirements, administrative controls will be established to provide assurance that the AOT extension is not applied during adverse weather conditions that could potentially affect offsite power availability.

Both the RBS risk-based analysis and the deterministic evaluation support the increased AOT. Therefore, this change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

2. **Will operation of the facility in accordance with this proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?**

The proposed TS changes do not involve a change in the design, configuration, or method of operation of the plant that could create the possibility of a new or different kind of accident. The proposed change extends the AOT currently allowed by the TS.

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

3. **Will operation of the facility in accordance with this proposed change involve a significant reduction in a margin of safety?**

The proposed extended AOT is not in conflict with any of the approved codes and standards applicable to the onsite AC power sources. The proposed changes do deviate from the recommendations of Regulatory Guide (RG) 1.93. An extension of the 72 hour AOT recommended in the RG to 14 days is demonstrated herein to be acceptable and has been approved for several other licensees. Assuming there are no additional failures of redundant equipment during the time that the EDG is removed from service, the intended safety functions would still be met.

The proposed AOT change does not affect any of the assumptions or inputs to the safety analyses of the FSAR and does not erode the decrease in severe accident risk achieved with the issuance of the Station Blackout (SBO) Rule, 10CFR50.63 "Loss of All Alternating Current Power". RBS is classified as a four-hour coping plant with 0.95 EDG reliability (see UFSAR Appendix 15C). The assumptions used in the SBO analysis regarding reliability of the EDGs are unaffected by the proposed TS changes since preventive maintenance and testing will continue to be performed to maintain reliability assumptions.

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

Based on the reasoning presented above and the previous discussion of the amendment request, Entergy Operations has determined that the requested change does not involve a significant hazards consideration.

7.0 ENVIRONMENTAL IMPACT EVALUATION

An evaluation of the proposed amendment has been performed pursuant to 10CFR51.22(b), which determined that the criteria for categorical exclusion set forth in 10CFR 51.22 (c) (9) of the regulations are met. The basis for this determination is as follows:

1. The proposed license amendment does not involve a significant hazards consideration as described previously in the evaluation.

2. This change does not result in a significant change or significant increase in the radiological doses for any Design Basis Accident. The proposed license amendment does not result in a significant change in the types or a significant increase in the amounts of any effluents that may be released off-site.

3. The proposed license amendment does not result in a significant increase to the individual or cumulative occupational radiation exposure because performance of EDG maintenance does not result in radiation exposure, regardless of whether the work is performed on-line or during outages.

Since the proposed amendment meets the criteria for categorical exclusion set forth in 10CFR 51.22 (c) (9) of the regulations, no environmental assessment is warranted.

ATTACHMENT 3

RBS PSA Peer Review Certification Information

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 October 1998. Table 1 provides a summary of the PSA Certification Team members' qualifications. 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.[3] Issues that are pertinent to the risk study in support of the EDG AOT extension are discussed below. The RBS PSA has also benefited from subsequent plant reviews of other BWR-6 plants through the sharing of industry experience and insights.

As described above, a peer review of the updated RBS PSA was completed in October 1998 by the BWROG in accordance with their certification guidelines. Overall, the peer review resulted in the conclusion that most of the elements of the RBS PSA were Grade 3 or suitable for supporting risk-informed applications such as changes to the TS. The review team identified four facts and observations (F&Os) with the significance level of "A" and 76 F&Os with the significance level of "B". The significance levels have the following definitions.

- A - Extremely important and necessary to address for ensuring the technical adequacy of the PSA, the quality of the PSA, or the quality of the PSA update process.

- B - Important and necessary to address, but may be deferred until the next PSA update.

Listed below are all the level "A" F&Os with resolutions. All open level "B" F&Os that are related to a sub-element receiving a grade less than "3" are shown in Table 2 with a status. An EDG AOT risk impact is also provided. The majority of the items identified in Table 2 would have minimal impact on the risk study because they do not impact Loss of Offsite Power

[3] The BWROG PSA Peer Review Certification program does not specifically evaluate the PSA models for a particular application such as an EDG AOT extension. However, the grading process for the Certification Program is intended to indicate the types of PSA applications for which the attributes of the PSA are suitable. Those certification elements receiving Grade 3 are deemed to be suitable for types of applications such as single TS actions if supported by deterministic evaluations. Not all areas of the PSA have to be assigned Grade 3 or greater to be suitable for TS changes. An important aspect of the certification process is the development of Facts & Observations (F&Os) that describe the issues relevant to particular sub-elements of the PSA. The impact of these issues on the particular PSA application being developed should be understood and addressed as appropriate.

(LOOP) events or systems used to mitigate LOOPs (i.e., a number deal with Anticipated Transient Without Scram (ATWS) or Interfacing System Loss of Coolant Accident (ISLOCA) events).

Level A F&Os

1. Accident Sequence Evaluation - The ATWS event trees appear to have some issues that may be in conflict with the EOPs. These include the following:

   - HPCS is considered a successful injection source. The EOPs do not cite HPCS to be used in ATWS. Depressurization to use LPCI would occur first along with the requirement to use LPCI.

   - SSW is listed as a potential injection system. This is also not included in the EOPs.

   RBS Resolution:
   The ATWS event tree was revised to correctly reflect the EOP guidance with respect to HPCS injection as part of PSA Model Revision 2D. Service Water is listed as an alternate injection system in the EOPs; therefore, no change regarding Service Water was necessary. ATWS remained a negligible contributor to CDF.

2. Accident Sequence Evaluation- Credit is taken for firewater injection in the short term since the station blackout procedure AOP-50 directs the operator to prepare the system for injection into the vessel. AOP-50 requires operation of 15 valves in four buildings. Taking credit for fire water injection with so many steps involved appears optimistic.

   RBS Resolution:
   Abnormal Operating Procedure AOP-0050, Station Blackout, directs the operator to prepare the Fire Protection Water (FPW) system for use in providing injection into the vessel. The procedure contains specific instructions for aligning the FPW, SSW, and RHR valves necessary for FPW injection into the reactor vessel. Since all of the valves required to be manually operated for aligning Fire Protection Water during station blackout are accessible, credit is given for Fire Protection Water injection in the station blackout event tree. Under station blackout conditions, the FPW system must be aligned manually, including manually opening valves, for use as an injection source. Therefore, there must be sufficient time available to align FPW before core damage occurs. If there are no stuck open relief valves, it takes approximately 75 minutes for core damage to occur with no injection, i.e., HPCS and RCIC failing at the start of the event. Therefore, it is assumed that if there are no stuck open relief valves (SORVs), FPW is a viable source for low pressure injection. If there is one SORV, the increased loss of coolant will decrease the available time for alignment of FPW. Therefore, it is assumed that another injection system, specifically RCIC, must initially

succeed for station blackout sequences with one SORV in order for there to be sufficient time for FPW to be aligned. For the case of station blackout sequences with two SORVs, RCIC is not able to maintain level. Therefore, it is assumed that FPW cannot be aligned in time for station blackout sequences with two SORVs. Operators are adequately trained on AOP-0050 to ensure completion of Attachment 2 within the required time.

3. Thermal Hydraulic Analysis - The technical basis for the success criteria used for sequences using only CRD injection could not be identified. A plant specific analysis (possibly including a test) is believed to be required to establish whether adequate CRD flow is available.

   RBS Resolution:
   PSA Model Revision 2D revised the event trees so that no credit is assumed for the operation of two CRD pumps in the enhanced flow mode for initial level control. CRD is credited for long-term inventory control.

4. System Analysis – RPS-The system notebook for RPS includes a set of cutsets that totals 1.5E-7. The following observations relate to these:

   - The conditional probability assessed with the "simplified " fault tree is far below that used in the industry to represent scram failure - 3E-5.
   - The NRC established the value of 3E-5 for scram system reliability in NUREG-0460. This predated the Browns Ferry failure to scram event. If the Browns Ferry event is included without rectification, the mechanical scram failure probability would be 1E-3 to 5E-3. Only with the argument that failure modes akin to Browns Ferry have been rectified could a value like 3E-5 be justified.
   - Detailed fault trees of the RPV system were developed by GE prior to NUREG-0460 and the Browns Ferry incident, their numerical values were in the 1E-7 range. However, the NRC assessed these estimates to be difficult to justify because in general fault tree methods have difficulty calculating estimates of highly redundant systems.
   - The single failure of an SDV full or blocked should be a single event causing scram failure—yet this is not observed and the blockage failure mode has no technical basis presented. This would be expected to model the Browns Ferry precursor.
   - The technical basis to support the assignment of dominant common cause failures of the scram system is not documented.
   - The ATWS Instability Fault Tree from which this fault tree was derived was developed for failure to insert any negative reactivity. This is a different success

criterion than the PSA requirement for the scram system to support the PSA ATWS sequence evaluations. Therefore, the ATWS instability fault tree cannot be used for the PSA without significant additional technical justification.

- There does not appear to be a way to distinguish between mechanical and electrical failures to insert control rods.
- Manual rod insertion when the failure is due to mechanical binding or scram discharge volume full does not appear to be treated as a dependent event contingent on the mechanical scram failure.
- The notebook seems to indicate that there is no human action involved with RPS or its failure modes, however the cutsets include many HEPs
- Scram system precursor failures are not addressed.

RBS Resolution:
The RPS-Mechanical fault tree credits the system changes to the scram discharge volume since the Browns Ferry precursor. Since the Browns Ferry ATWS, redundant level instrumentation and annunciation of the SDV have been added which greatly reduces the likelihood that the SDV will be filled at the time of the event. Two of the contractors who participated in the PSA development were Browns Ferry employees at the time of the precursor. These contractors reviewed the fault trees and ensured that the Browns Ferry precursor was accounted for. In addition, the RBS SDV vent and drain valves are normally opened to prevent an accumulation of water in the SDV before a scram.

It is true that the fault trees developed for the ATWS instability event evaluate failure of all 145 control rods to insert. However, the ATWS event is generally described as failure of multiple control rods to insert and per the EOPs would result in reactor power above 5% following the scram signal. The common cause failure probability of an additional failure given three failures is assumed to be one. Therefore, the common cause failure events (which will dominate any RPS model) are no different for a partial failure to scram than for a full failure to scram. In addition, the RPS fault trees for RBS account for the very short mission time for rod insertion. The components only need to be available for a very short period needed to drive the control rods into the core. Therefore, failure probabilities for many components would be very low. In addition, we did not find any single failures that would result in failure of individual rod groups to insert.

The RPS fault trees are very detailed analysis of the RPS system at RBS. These fault trees include failures of relays and circuits needed to insert the rods as well as piping blockage and rupture failures. Separate fault trees exist for the RPS-Mechanical, RPS-Electrical, Alternate Rod Insertion, and Manual Rod Insertion tops as represented in the ATWS event tree. Per the ATWS event tree, if the mechanical systems to insert the rod do not function, the success of electrical signals for rod insertion will not prevent an ATWS.

NUREG/CR-5500, Volume 3, Reliability Study: General Electric Reactor Protection System, 1984-1995, documents a "moderately detailed fault tree of the General Electric relay-based RPS... ATWS mitigation systems such as ARI, SLCS and ATWS-RPT, were not included in the fault tree model. The RPS fault tree quantification resulted in a mean unavailability of 5.8E-6 (with no credit for manual scram by the operator)....The RPS fault tree was also quantified allowing credit for manual scram by the operator (with a failure probability of 0.01). The resulting RPS unavailability is 2.6E-6." The calculated value for the RBS RPS unavailability is an order of magnitude lower than the value documented in this study. As noted earlier, the RBS evaluation accounted for the RBS specific design. For any automatic scram signal, the RPS system would automatically insert the control rods. However, these automatic signals can fail due to an electrical malfunction. As a backup measure, AOP-001 includes an immediate operator action to arm and depress the manual scram pushbuttons for RPS and ARI upon indication of a scram signal. This human action is modeled in the RPS fault trees as a backup to the failure of the automatic signal. Essentially, this human action is no different than a manual start of an ECCS system if the automatic start does not occur. The only difference is that the likelihood of success for this human action is much higher than a manual start of an ECCS system since the action is performed for every scram event regardless of whether the automatic signal occurred or not.

These enhancements did not receive a formal industry peer review such as from the BWROG PSA Peer Review process. However, the resolutions were reviewed by RBS and by other EOI PSA personnel.

Table 1: PSA PEER REVIEW CERTIFICATION TEAM EXPERIENCE

TEAM MEMBER	EXPERIENCE SUMMARY			
	Degree	Years Experience	Years of PSA Experience	Selected PSA Projects
C.E. Buchholz	BS - Nuclear & Mechanical Engineering - UC Berkeley MS - Mechanical Engineering, UC Berkeley	13	7	• Level 1 for Alto Lazio, ABWR, SBWR, Lungmen • Level 2 for ABWR, SBWR, Lungmen
E. T. Burns	BS, Engineering Science - RPI MS, Nuclear Engineering - RPI Ph.D., Nuclear Engineering , RPI	26	21	• Technical reviewer of Level 1 IPEs for fifteen BWR plants • Manager, technical advisor, or lead engineer on many IPEs/PSAs for BWR plants • Lead engineer on several containment safety studies
S. Visweswaran	B. Tech - Mechanical Engineering, Indian Institute of Technology, Kharagpur, India MS - Industrial Engineering, UC Berkeley	30	20	• Technical lead for a number of BWR PSAs • Consultant to Utilities for BWR PSAs
W.J. Colvin	BS, Mechanical Engineering, Cleveland State MS, Nuclear Engineering, Univ. of Cincinnati	20	8	• Manager of Level 2 PSA for Perry • Support of Level 1 PSA for Perry • Manager of Maintenance Rule Response for Perry

Table 1: PSA PEER REVIEW CERTIFICATION TEAM EXPERIENCE

TEAM MEMBER	EXPERIENCE SUMMARY			
	Degree	Years Experience	Years of PSA Experience	Selected PSA Projects
Mariano Fiol	BS, Physics (UIB) MS, Nuclear Engineering (CIEMAT) MS, Environmental Engineering (EOI)	10	10	• Cofrentes NPP (Spain) Level 1 PSA development and licensing • Level 1/2 interface development and Level 2 review and coordination • Several PSA applications

Table 2 provides all open level "B" F&Os that are related to a sub-element receiving a grade less than "3." Table 2 also summarizes the impact the F&O would have on the EDG AOT risk study.

Table 2 Significant PSA Certification Facts and Observations

PSA Certification F&O	**EDG AOT Risk Impact**
Initiating Events (IE)	
Special initiating events were discussed in the initiating event notebooks. However the following initiating events are believed to be incorrectly screened from the quantification process: • Breaks outside containment(BOC) 1. Main steam line 2. Feedwater lines 3. RCIC & RWCU Lines The analysis is completely adequate and appropriate for an IPE study or a study comparable to NUREG-1150. NUREG-1602 (DRAFT) has indicated similar concerns by stating that a steam generator event may have a relatively low contribution to the total core damage frequency but may constitute a significant fraction of total large early releases. Initiating events such as these should not be excluded.	No impact. Current assumption meets NUREG-1602 screening criteria. This will be documented.
Technical Basis for ISLOCA is not provided. • Isolation of large breaks • ECCS viability without isolation of large break This basis may include the basis for only considering small interface breaches and not large ruptures.	No impact - ISLOCA does not contribute to RBS CDF. The ISLOCA frequency will be revised using NSAC-154.
Initiating frequency of common cause 125V DC seems low and does not appear to account for common cause failures.	No impact - An evaluation to justify why common cause failure of DC busses is not likely is provided in Appendix A to Attachment 3.

Table 2 Significant PSA Certification Facts and Observations (continued)

PSA Certification F&O	**EDG AOT Risk Impact**
Accident Sequences (AS)	
No technical basis is provided for the assumption that RPT failure does not lead to RPV overpressure.	No impact. Information that SRVs can remove 112% reactor pressure will be added.
RCIC failure mode due to HEP of door opening not addressed in model	Minimal impact - RCIC temperature trip is bypassed. Potential operator action to open door may provide more time before RCIC temperature trip.
For ADS inhibit, the stress and time available for the action create a situation where extremely low HEP estimates are not judged reasonable given the current state of the HRA technology.	No impact - ATWS is a negligible contributor to the overall CDF. Also, ADS is not credited for SBO sequences because the low pressure ECCS pumps would not automatically start. The ADS logic requires a low pressure ECCS pump to start and run for initiation. Finally, the current ADS inhibit HEP value is 1E-6. Given the current operators training on the importance of inhibiting ADS for ATWS events and the fact that it is one of the first actions performed for ATWS events, it is doubtful that the failure to inhibit ADS probability would increase significantly.
Containment venting assessment does not consider all vent paths directed by EOPs.	No impact - The assumptions match the EOPs and SAPs; however, they could be clarified.
Include event with ATWS and stuck open SRV	No impact - ATWS is a negligible contributor to the overall CDF. One or more SRVs will be opened throughout the event for pressure control.
The assessment of possible stuck open relief valves (SORVs) is desirable to include in the quantified model because they can influence the operator response to control RPV level when RPV pressure inadvertently drops below the low pressure injection shut off for condensate, LPCI, and LPCS. Simulator observations at BWRs have indicated that a stuck open relief valve during a failure to scram event (where SLC is injected by procedure) can lead to a situation where slow RPV depressurization occurs to below the shut off head of low pressure systems -- which if not terminated (e.g., in pull-to-lock) can reflood the RPV and washing boron from the RPV. It is the issue of inadvertent depressurization occurring as SLC is successfully injected that leads	No impact - ATWS is a negligible contributor to the overall CDF. Typically, ATWS events result in emergency depressurization. A TH analysis for this issue will be necessary.

PSA Certification F&O	EDG AOT Risk Impact
to a unique operator challenge and the need to assess the operating crew response under these conditions.	
CRD injection is assumed not affected by the containment failure mode. The catastrophic failure of a steel shell has a reasonable probability of causing disruption of the shell and of small inject lines that may penetrate it.	No impact - Energetic failure of containment will be addressed in the PSA Assumptions calculation if/when updated.
Thermal Hydraulic (TH)	
SLC Injection Timing - The key timing interval(s) for ATWS analysis sequences should be based valid on thermal/hydraulic analyses which directly correspond to the PSA sequences and the clearly document the impact of not meeting the success criteria.	No impact - ATWS is a negligible contributor to the overall CDF. The SLC injection timing was revised. The HRA will be updated.
Human Reliability Analysis (HR)	
This observation is related to the treatment of the low pressure permissive miscalibration of the injection valves on low pressure systems. • The permissive is included in the model as a single event • This event is assessed at 1E-5 (ESF-CCFHMCRXPRES) The issues are as follows: The text indicates there may be 2 separate logic systems. This does not appear to be included in the model: i.e., LPCI B & C AND LPCI A & LPCS. The model may conservatively include only a single miscalibration or the text may be incorrect. The HEP of 1E-5 appears optimistic. A value of 1E-4 is more typical but could be justified to be a factor of 2 to 3 lower.	Minimal impact - Some of the logic for LPCI A & LPCS is shared and some of the logic for LPCI B & C is shared; however, some of the logic is independent. The potential for separate miscalibration of LPCI A & LPCS and LPCI B & C will be reviewed.

Table 2 Significant PSA Certification Facts and Observations (continued)

PSA Certification F&O	EDG AOT Risk Impact
HEP consistency - An emergency depressurization HEP of 2E-3 is judged to be conservative. This assessment is then compared with other actions that have similar or lower HEPs to judge the overall self consistency among the HEPs. The alignment of the SBO DG in a complete SBO under severe weather conditions and on the back shift is evaluated to have a lower HEP than the emergency depressurization despite the many local manual actions required. The ADS inhibit action is evaluated as two orders of magnitude below the HEP for ED despite the extreme stress and the shorter time frame.	No impact. As stated, the HEP for Emergency depressurization is 2.0E-3. However, the HEP for "OPERATOR FAILS TO ALIGN THE SBO DIESEL BEFORE 4 HOURS" (EPS-HEEHFRSBODC) is 1.0E-1. Therefore, this is not an issue. As for ATWS events, ADS inhibit is the first action taken in EOP-1A. ATWS is a well trained event and the need to inhibit ADS is well understood by all of the operators. The HEP for this event was reviewed and approved by Dr. Alan Swain, the developer of the THERP methodology. The HEP action is to turn two key switches on Panel H13-P601. The keys are in the switches so there is no need to search for the appropriate key. While the HEP value is generally less than reported in most PRAs, we believe that the value is appropriate because the EOP-1A event associated with the action has not changed and the review by Dr. Swain implies that the THERP methodology was appropriately performed. Based on comments from several operators, as well as several people who have been through the operator training, ADS inhibit is a well memorized action for ATWS events and the operators would not fail to do this during an ATWS.
Operations Review of HRA assumptions - There is no evidence that the HRA assumptions regarding timing, priorities, and ease of diagnosis have been reviewed by the operating staff. The PRA team had members who were previously involved in plant operation. While this is a plus, it is not a replacement for review by the current operating staff. The HRA should reflect the operating procedures as understood and followed by the operating staff.	No impact – Administrative recommendation to have Operations review HRA. One of the inputs to the HRA is operator interviews.

Appendix A

Justification of NO IMPACT for PSA Certification F&O Concerning Common Cause Failures of 125 VDC

F&O: Initiating frequency of common cause 125V DC seems low and does not appear to account for common cause failures.

The particular common cause issue addressed here includes failure of the initial bus coupled with a human error in response to this alarm. The human error of performing a maintenance or test action on the "wrong" bus, i.e., the operable bus while trying to trouble shoot the inoperable bus would appear to be a primary candidate for consideration.

Resolution: For RBS, the initiating event is based on a failure of a single bus. The value is a factor of 2 to 6 higher than the industry experience frequency of 1E-3/yr (see below). The loss of power to the bus is annunciated in the control room (H13-P808/87). Therefore, any bus undervoltage or loss of power to the DC bus is known immediately. Also, the plant must shutdown within two hours of a loss of a DC bus per Technical Specification 3.8.4. The likelihood of an event occurring which causes both DC busses to fail is extremely low based on the DC bus failure rate (1E-7/hr), the fact that both busses are normally energized and the fact that the unlikely failures would have to occur within such a short time frame (2 hours). There do not appear to be any common environmental, spatial, testing, or maintenance events that would lead to the busses failing concurrently. For cases where the battery or charger for the system failed, the plant would shut down in anticipation of a loss of DC rather than for an actual loss of DC event. However, an evaluation of a DC Bus common cause failure is evaluated below.

DC BUS COMMON CAUSE FAILURE

The failure of DC buses has been postulated to occur based on operating experience observations.

<u>Loss of A Single 125V DC Bus</u>

The loss of 125V DC power to a single bus can be estimated from past nuclear operating experience data. Those loss of power events involving the loss of a DC bus are summarized in Table A-1. The important incidents in Table A-1 are those in which the loss of a vital (safety-related) DC bus is coincident with a reactor shutdown challenge. Using an estimated 996 years of bus experience as cited in NUREG 0666 for quantification of a single DC bus failure, the estimated frequency for loss of a single DC bus is then calculated from these three events as follows:

$$T_{DC} = \frac{\text{3 events of loss of DC bus leading to scram}}{\text{996 years of DC bus operation}}$$

$$T_{DC} = 3.0\text{x}10^{-3} \text{ per bus year}$$

Two of the three documented industry events for DC bus failure were listed as "battery drained". It is assumed that the two "battery drained" errors are precluded from occurring at RBS because of procedures for testing and monitoring battery chargers. Thus, the "DC Bus Failure" initiating event frequency could be changed from 3E-3/yr to 1E-3/yr.

Eliminating the 2 battery drain down events results in a lower estimate for the loss of DC bus frequency as follows:

Using 1 event/1000 Bus-Yr. = 1E-3/Bus-Yr.

Multiple 125V DC Bus Failure

NUREG-0666 estimates the frequency of multiple DC bus failures due to identified common-mode failures. The base DC system assumed in NUREG-0666 has the following features:

- Two buses with one charger per bus;
- A normally open manually operated cross-tie breaker connecting the two bus divisions; and
- A minimum standard testing and surveillance schedule.

NUREG-0666 indicates the following reliability improvements are possible if the system differs from that in NUREG-0666:

- A factor of 50 for removal of bus ties among DC power supplies,
- A factor of 10 for change in surveillance and maintenance philosophy, and
- A factor of 100 for the addition of a third bus.

The overall reliability improvement is limited to a factor of 50.

Beginning with the NUREG-0666 baseline conditional probability of a multiple DC bus failure given a single bus failure (0.003/challenge) and reducing this by the factor of 50 for a superior configuration, the calculated conditional failure probability of the second DC bus given that the first bus has failed is 6E-5/challenge in the best possible configuration.

Conclusion

The initiating event frequency for a loss of two DC buses under the most optimistic assumptions from NUREG-0666 is:

1E-3/yr. * 6E-5 = 6E-8/yr.

Based on this low event frequency, cutsets containing this event would most likely be truncated or, at best, be very small contributors to the overall CDF. Therefore, this event would not impact the EDG AOT CDF values.

Table A-1: SUMMARY OF LICENSEE EVENT REPORTS CONSIDERED IN ESTABLISHING
THE INITIATING FREQUENCY OF LOSS OF DC POWER BUS

Plant	DATE	Duration	Type of Error	Plant Condition
Dresden 2	3/21/78	42 min	Personnel	No Scram
H.B. Robinson 2	3/10/72	---	Battery drained	Reactor Scram
H.B. Robinson 2	7/10/76	< 60 min	Personnel	No Scram
Palisades	6/9/74	< 60 min	Breaker	No Scram
Prairie Island 2	4/14/76	5 min	Battery charger	No Scram
Quad Cities 2	8/31/74	---	Battery drained	Reactor Scram
Zion 2	9/19/76	< 60 min	Personnel	Reactor Scram

ATTACHMENT 4
Description of RBS PSA Model Changes

PSA Model Revision 2D Major Model Changes

This revision of the PSA incorporated the changes to the plant between October 1, 1997, and May 31, 1999. It also incorporated some of the comments from the River Bend PSA Peer Review conducted under BWROG auspices. The Peer Review comments addressed as part of model revision 2D were those with a high potential to impact the calculated model results and which could be implemented as part of revision 2D within the existing manpower restraints.

- Plant Modifications and Procedure Changes

The major modifications that were incorporated in PSA Revision 2D are the re-routing of the RCIC injection from the RPV spray nozzle to the Feedwater A injection line (MR 96-096) and the conversion of the Division I and II EDG starting air systems from non-safety to safety-related (ERs 98-0426 and 98-0585). Two other RCIC modifications were incorporated into the fault tree models: MR 95-0534 determinated and locked open lube oil cooler valve E51-MOVF046 and MR 96-0063 removed the check valve internals from turbine exhaust check valve E51-VF040.

In addition to the plant modifications, two procedure changes impacted the RCIC fault tree. The first procedure change is the addition of an EOP enclosure to bypass RCIC trip on high temperature. This change allows RCIC to run following a loss of ventilation in areas were RCIC steam piping is located. The second change is an AOP-0050 change to instruct the operators to swap RCIC flow back to the CST during a station blackout. The RCIC setpoint for high suppression pool level swap is below the Tech. Spec. maximum suppression pool water level. If the MSIVs close and the SRVs open for pressure relief, the suppression pool will swell. RCIC suction will probably swap to the suppression pool before the operators can prevent the swap. The operators need to swap RCIC flow back to the CST to prevent RCIC failure due to suppression pool heatup.

- PSA Model Level of Detail Changes

Several changes were made to the PSA model to enhance the level of detail. Many of these changes involved the incorporation of shutdown EOOS models into the Level 1 PSA models. The offsite power model was modeled back to the Fancy Point substation. The HPCS and RCIC models were expanded to include alignment to the suppression pool rather than the CST. The partial loss of offsite power to non-safety related systems was included to the individual pumps.

Two changes were made to the EOOS models to support alternate modes of operation that were included in the EOOS model during the cycle. The first mode involved providing alternate alignment of offsite power to the ENS busses. This fault tree modification allows an alternate lineup from RTX-XSR1D to ENS-SWG1A and RTX-XSR1C to ENS-SWG1B. The other change allows the alignment of service water train A to the CCP heat exchangers. Normally, the CCP heat exchangers are aligned to service water train B. This alignment ensures that, in the event of an accident, a single train A service water pump can supply the necessary heat removal without pump runout.

The fault tree models for the emergency diesel generators were enhanced to include the starting air system and the fuel oil system. The failure rates of these components are set to 0.0 since the failure of these support systems is included in the plant specific diesel failure rates. The models for the starting air and fuel oil were provided for EOOS mapping purposes. Previously, all support system failures were mapped directly to a failure of the diesel. The current support system models show the redundancy in the support systems and allow for more accurate results in EOOS quantification of risk for on-line maintenance.

- Incorporation of Plant Specific Data

The plant specific initiating event frequencies were updated based on plant shutdowns since 1992. In addition, the manual shutdowns since 1987 were reviewed and incorporated in the plant data. The results of the plant specific data show a reduction in transients with PCS available (INI-T3A), transients without PCS available (INI-T2), loss of feedwater (INI-T3B), and stuck-open relief valve (INI-T3C) initiators. The partial loss of offsite power initiators increased slightly.

In addition, the special initiators were recalculated to correct an error in the initiating event frequencies for TNSW, TCCP, TCCS, and TIAS. The initial calculation did not account for all possible combinations of failures leading to the initiator. The TIAS frequency was recalculated based on the new IAS model incorporated in Revision 2A. The initiating event frequencies for each of these events increased by a factor of 1.5 to 2.

The loss of offsite power recovery calculation was updated based on EPRI TR-106306 (Losses of Offsite power through 1995). The later data shows a greater number of loss of offsite power events that lasted for four or more hours before offsite power could be recovered. This calculation significantly increased the non-recovery values for short-term recoveries.

Plant specific failure rates for RCIC, emergency diesel generators, and HPCS were incorporated in the PSA based on current data. The RCIC failure to start and maintenance unavailability showed improvement from the previous revision of the PSA. The HPCS failure to start increased significantly due to failures since the last revision. The diesel failure to start and failure to run increased due to additional failures since the last revision. The diesel generator maintenance unavailability showed a slight improvement from the previous revision.

- Incorporation of PSA Certification Comments

The BWROG River Bend PSA Peer Review Certification included numerous comments on changes to enhance the PSA. Many of these comments are not expected to impact the model and will be updated in a future revision of the PSA. Several comments were incorporated in this revision of the PSA. The comment that had the largest impact on the PSA results was that two pump CRD flow probably would not be sufficient to maintain RPV level unless another high pressure injection system worked initially. Note that this assumption was originally included consistent with NUREG-4550 and was reassessed due to the PSA Peer Review. This change and the increase in HPCS failure rate resulted in an increase in CDF.

The human error probability for failure to manually depressurize was updated to more accurately reflect the importance of depressurization in operator training. The probability for this event was changed from 2E-3 to 1.7E-4.

The ATWS event tree was updated to include the latest changes to the EOPs. The ATWS event tree was also updated to include the results of power uprate conditions. The frequency of an ATWS event is still very low. Therefore, ATWS was a negligible contributor to overall CDF.

Several other minor changes to the fault trees and quantification were corrected to improve the accuracy of the results. These changes involved including additional common cause failures, correcting minor fault tree modeling mistakes, and adding maintenance combinations to the mutually exclusive events file. Some of these changes did appear in the final results but did not significantly impact the overall results.

PSA Model Revision 3 Major Model Changes

This revision of the PSA represents the plant as of November 1, 2000. Since revision 2D of the PSA no plant modifications were done that impacted the PSA model. The same is true for plant procedures. However, since revision 2D there have been analyses that changed data that impacted documentation supporting the PSA model. From an analysis of containment it was determined that containment failure occurred sooner than previously assumed. This impacted the recovery action for long term decay heat removal. An additional analysis was done to determine the effect of containment failure on auxiliary building equipment. Insights from this analysis resulted in a change to several of the event trees.

Several basic events were added to the basic event file. In general, these additions were the result of PSA model expansion. PSA model expansion was done to include plant systems, components, lineups, etc. that had not been included in previous revisions. These basic events were not added in response to plant modifications or procedure changes.

Also, since the last revision power uprate has been implemented. The PSA model including supporting documentation was reviewed to determine if the implementation of power uprate impacted the PSA. When the review was completed it was determined that no changes were needed to the model as a result of power uprate. There were no physical modifications to the plant for power uprate that impacted the PSA model. The HRA that was in place prior to power uprate implementation remained conservative when the 5% power uprate implemented in Fall 2000 was incorporated. Therefore, no changes were needed to the HRA for power uprate. There was no change in the time to core damage from pre-power uprate conditions. Consequently, there was no change in supporting documentation for the PSA.

- Plant Modifications and Procedure Changes

There were no modifications done to the plant or procedure changes since the last revision that impacted the PSA model. Therefore, no changes were made to the PSA in response to plant modifications or procedure changes in this revision.

- PSA Model - Level of Detail Changes

Several changes were made to the PSA model to enhance the level of detail. Many of these changes were the result of changes in documentation that supported the Level 1 PSA.

The greatest change in the revision 3 model is modification to the event trees. The modification comes as a result of an analysis that shows containment failure occurs sooner on loss of all decay heat removal than previously assumed in revision 2D. Further analysis confirmed that containment failure caused overpressurization and failure of ductwork in the Auxiliary Building. The analysis showed that failure of the ductwork exposed motor control centers in the Auxiliary Building to a steam environment. This would cause power supply failure to the HPCS pump room unit cooler. With no cooling to the HPCS pump room it is assumed that the pump motor would over heat and fail. Likewise, it was assumed that LPCS and the RHR pumps would fail for similar reasons. It was also assumed that a steam environment in the Auxiliary Building would impact control power to all the SRVs possibly causing them to close. Once the SRVs are closed the containment will re-pressurize preventing injection with FPW or SSW. Finally, it was assumed that the steam environment could cause the spurious closure of the SSW to LPCI B cross tie MOV. The event trees were changed to reflect these conditions.

The probability for the recovery action used in sequences representing long term loss of decay heat removal was changed. Containment failure analysis determined that the containment fails earlier than assumed in the revision 2D. In revision 2D it was assumed that the containment fails in 26 hours on loss of all decay heat removal. A later calculation initiated to investigate the impact of power uprate determined that the time to failure for the appropriate severe accident scenario is 16 hours. Therefore, the probability to not recover decay heat removal was adjusted to represent non-recovery in 16 hours. This resulted in a slightly higher probability of non-recovery of decay heat removal.

The instrument air system (IAS) fault tree was expanded to include the service air system (SAS) as backup.

- PSA Model – Offsite Power Recovery Level of Detail and Industry Data Changes

The probability of non-recovery of offsite power was changed to include additional industry data accumulated since revision 2D. A new curve for non-recovery of offsite power following a loss of offsite power was generated to include the new industry data. This calculation was also done to revise the offsite power recovery models. They were revised to improve internal data consistency and to adapt a Weibull distribution that resulted in an improved fit to the industry experience data. The overall result was an increase in probability of non-recovery of offsite power. One additional major contribution was the updated industry data, including the event where it took 23 hours to recover from a loss offsite power caused by a tornado at Davis Besse.

A recovery action was added to the model to represent non-recovery of a diesel generator when a diesel generator failed to start, failed to run, or the auto start signal failed to start and load the diesel. As with most recovery actions this recovery action lowered the core damage frequency of sequences that contained a failure to start, failure to run, or failure of the auto start signal to start and load a diesel generator. Assuming at least an hour prior to core damage with no vessel injection, a value of 0.9 was assigned to this recovery action based upon NUREG-4550, Table 8.2-10.

- Incorporation of Plant Specific Data

No additional plant specific data was incorporated in this revision of the PSA model. Plant specific data for selected plant systems were incorporated in revision 2D.

- Incorporation of PSA Certification Comments

The BWROG River Bend PSA Peer Review Certification included numerous comments on changes to enhance the PSA. Many of the significant comments (A and B) were incorporated in PSA model revision 2D. Most of the remaining significant comments as well as some enhancements were incorporated in this revision. The balance of comments will be addressed during PSA upgrades to follow PSA model revision 3.

PSA Model Revision 3A

These changes to the PSA model are considered enhancements and have helped to reduce the overall Level 1 CDF by a factor of two.

- Use of Convolution for Offsite Power Recovery

As noted previously, the probability of non-recovery of offsite power was changed in Revision 3 to include additional industry data accumulated since revision 2D. A new curve for non-recovery of offsite power following a loss of offsite power was generated to include the new industry data. The overall result was an increase in probability of non-recovery of offsite power. One major contribution was the updated industry event in which it took 23 hours to recover from a loss offsite power caused by a tornado at Davis Besse.

As a result, accidents initiated by LOOP events were important risk contributors both in terms of core-damage frequency and consequence. Thus, to assure an accurate assessment of these accidents, it was important to account for the likelihood of recovering off-site power prior to core damage. To accurately evaluate the non-recovery of offsite power, the LOOP recovery curve was used to develop recovery integrals using convolution. Convolution is an established method of determining offsite power non-recovery frequencies. It can be understood by considering a hypothetical plant having a single diesel generator. It is assumed that core damage will occur if an LOOP initiating event occurs, the diesel generator fails to run, and OSP is not recovered within T_c hours after the diesel generator fails. The quantity T_c is the time required to boil away the primary inventory following a total loss of AC power. This cut set might be represented by:

$$\text{cut set} = LOSP * DGR * NROSP$$

The frequency of this cut set is given by:

$$f(\text{cut set}) = f(LOSP) \times P(DGR * NROSP)$$

To estimate P(DGR*NROSP), the time axis is divided into a number of small intervals, each having a duration of Δt so that the starting point of each interval is given by $t_n = n\Delta t$ for n = 0,1,2,...The probability that the diesel generator fails during the nth interval and the OSP is not recovered is given by:

$$\Pr\{\text{diesel runs to time } t_n\} \times \Pr\{\text{diesel fails in } [t_n, t_n + \Delta t]\}$$
$$\times \Pr\{\text{OSP not recovered by time } t_n + T_c\}$$
$$= \left[\exp(-\lambda t_n)\right]\left[\lambda\,\Delta t\right]\left[G(t_n + T_c)\right]$$

Summing over all intervals and allowing Δt to approach zero yields:

$$P(EDGR * NROSP) = \lim_{\Delta t \to 0} \sum_n \left[\exp(-\lambda t_n)\right]\left[\lambda \Delta t\right]\left[G(t_n + T_c)\right]$$

$$= \int_0^\infty \lambda e^{-\lambda t} G(t + T_c)\, dt$$

This integral is termed a "convolution integral" since its functional form resembles the convolution of Fourier transforms. A more powerful approach, which is capable of addressing multiple run failures in a single cut set, is to state the problem in terms of random variables and their probability density functions (pdfs). Let T_D be a random variable denoting the time when the diesel fails and T_R be a random variable denoting the time when OSP is recovered. Then:

$$P(EDGR * NROSP) = \Pr\{T_R > T_D + T_c\}$$

A basic theorem in probability theory states that the probability that a set of random variables assumes values in a region R may be found by integrating the joint probability density function of the random variables over the region R:

$$\Pr\{(T_D, T_R) \in R\} = \iint_R f(t_D, t_R)\, dt_D\, dt_R$$

Applying this theorem to the diesel generator run failure and OSP non-recovery shows that the region R is given by:

$$R = \{(t_D, t_R) \text{ such that } 0 < t_D < \infty \text{ and } t_D + t_c < t_R < \infty\}$$

Converting the double integral into an iterated integral yields:

$$P(EDR * NROSP) = \Pr\{T_R > T_D + t_c\} = \iint_R f(t_D, t_R)\, dt_D\, dt_R$$

$$= \int_0^\infty \int_{t_D + t_c}^\infty \lambda e^{-\lambda t_D} g(t_R)\, dt_R\, dt_D = \int_0^\infty \lambda e^{-\lambda t_D} G(t_D + t_c)\, dt_D$$

Thus, the convolution approach consists of integrating (or convoluting) the product of the probability density functions (pdfs) associated with the run failures in a given cut set with the OSP non-recovery probability. The convolution integral equals the mean probability that OSP is not recovered in time to prevent core damage for the given cut set. In a broad sense, the convolution process may be viewed as a time-averaging approach.

To apply convolution to the RBS PSA model, the first task was to identify the core damage sequences from the PSA model eligible for recovery. The timing of the identified core-damage sequence types was determined and time-line diagrams are developed. Based upon the time-lines, convolution integrals were developed. The convolution integrals were then solved to calculate the LOOP recovery factors. Below is a table that lists the ORAs included. These ORA categories represent the non-recovery of offsite power within a specified number of hours or minutes.

ORA Category	Description
ORA-OSP12HRS	Sequences involving LOOP and CHR failure at 12 hours
ORA-OSP6HRS	Sequences involving LOOP and CST depletion at 6 hours
ORA-OSP4HRS	Battery depletion in 4 hours
ORA-OSP2HRS	Sequences involving LOOP and RCIC failure on high suppression pool temperature at 2 hours
ORA-OSP1HRS	No trigger event case – Sequences involving no injection from time 0
ORA-OSP30MIN	Failure of two SRVs to reclose and no injection

Once the loss of offsite power recovery frequencies developed using convolution were incorporated into the RBS PSA model, the change in CDF was a reduction of approximately 25%.

- Recovery Action to Align Division III EDG to Division I Bus

Like other BWR 6s, RBS will develop a procedure to align the Division III EDG to the Division I or II bus. The procedure will be issued prior to implementation of the EDG AOT extension. The action to cross-tie the Division III EDG to the Division I or II 4.16 KV bus would be performed during a station blackout condition. The operators would be required to close the breakers between the Division III EDG and the 4.16 KV bus and energize specific loads in order to restore power to those components.

Based on discussions with plant operations and electrical engineering it would take approximately 3-4 hours to align the diesel generator once the decision was made to do so. The decision to align to the Division III EDG to provide power to a 4.16 KV bus would be made after attempts to restore the Division I and II EDGs failed. Therefore, the decision to perform this action would most likely occur 1-2 hours after the loss of offsite power occurred. Assuming 1-2 hours to make the decision that this action is necessary and 3-4 hours to perform the action, the time frame for performing this action is estimated to be 6 hours.

Although the procedure has not been generated as of the date of this submittal, it is possible to determine an estimate of the non-recovery frequency. Electric Power Research Institute (EPRI) TR-101711, SHARP1 - A Revised Systematic Human Action Reliability Procedure provides guidance for a human reliability analysis (HRA) qualitative determination of the relative likelihood of failure to accomplish recovery, based on a set of attributes for the action such as time available, training, complexity, and environment. For various combinations of these factors, a qualitative assessment can be made regarding the probability of failure. These qualitative assignments are then associated with a quantitative probability scale.

As mentioned previously, EPRI TR-101711, SHARP1 - A Revised Systematic Human Action Reliability Procedure provides guidance for an HRA qualitative determination of the relative likelihood of failure to accomplish recovery, based on a set of attributes for the action:

- The amount of time available for decision-making and action
  - Short,
  - Intermediate, and
  - Long;
- Whether training or some level of procedural guidance is available relative to the specific actions being considered;
- Whether the recovery action is simple (e.g., operating a manual valve) or complex (e.g., multiple steps required to cross-connect two systems); and
- Whether environmental factors, such as the heat, humidity, or radiation levels that might impede recovery efforts, are good or poor.

For various combinations of these factors, a qualitative assessment is made regarding the probability of failure. These qualitative assignments are then associated with a quantitative probability scale. The scale used in this study is the nominal scale provided by EPRI. The non-recovery probabilities in this scale are as shown in Figure 1.

Non-recovery event	Time available for action	Relative complexity of action	Availability of training or practice for action	Nature of environment for work area	Qualitative Probability of Failure	Quantitative Assessment
	long (12 hr)	simple	training/practice	good	low	0.01
				poor	mod. low	0.03
			no training/practice	good	mod. low	0.03
				poor	mod. high	0.05
		complex	training/practice	good	mod. low	0.03
				poor	mod. high	0.05
			no training/practice	good	mod. high	0.05
				poor	high	0.1
	intermediate (6 to 12 hr)	simple	training/practice	good	mod. low	0.03
				poor	mod. high	0.05
			no training/practice	good	mod. high	0.05
				poor	high	0.1
		complex	training/practice	good	mod. high	0.05
				poor	high	0.1
			no training/practice	good	high	0.1
				poor	very high	0.3
	short (6 hr)	simple	training/practice	good	mod. high	0.05
				poor	high	0.1
			no training/practice	good	high	0.1
				poor	very high	0.3
		complex	training/practice	good	high	0.1
				poor	very high	0.3
			no training/practice	good	very high	0.3
				poor	maximal	1

Figure 1 - Non-Recovery Event Evaluation Chart

Initial training as well as periodic review is credited. Based on the actions required and the care taken to prevent overload of the Division III diesel generator, the action is assumed to be complex. The action would require multiple steps. The individual actions are not necessarily complex, but the combination of actions is considered complex.

The working environment for aligning the Division III EDG to power the Division I or II bus is considered good. The diesel generator rooms would not be harsh environmentally or radiologically. Since this action would be performed during a station blackout, the lighting would not be optimal, but extra lights and flashlights could be brought in to ensure that the lighting is adequate to perform this task. Therefore, the working environment is assumed to be good.

The non-recovery probabilities in this scale are as shown in Figure 1. The events evaluated by applying this structure are summarized in Table 1.

Table 1 - Summary of Non-Recovery Event Results

Recovery Event Name	**Description**	**Qualitative Probability of Failure**	**Quantitative Assessment**
ORA-DGN6HRS	Failure to align Div III EDG to Div I or II bus within 6 hours	high	0.1
ORA-DGN12HRS	Failure to align Div III EDG to Div I or II bus within 12 hours	Mod. low	0.03

- Incorporation of a Human Reliability Analysis to Manually Open SWP-AOV599 if Needed

SWP-AOV599 is a bypass valve around SWP-MOV55A that supplies a return path for the Division III Standby Service Water Pump, SWP-P2C, if the Division I and II Emergency Diesel Generators fail and the Division III (HPCS) Diesel Generator and SWP-P2C initially start. If SWP-AOV599 does not open, the Standby Service Water system would quickly fill the Normal Service Water Surge Tank and the flow would then "dead head" in the SSW piping. A small amount of flow would still be provided through the opened Surge Tank relief valves. However, this flow would be much less than required to adequately cool the HPCS Diesel Generator. Based on the timeline provided by the System Engineer for diesel failure on loss of Service Water, the HPCS diesel would fail in 4 minutes, 58 seconds (reference RBG-45648 dated February 8, 2001).

AOP-0050, Station Blackout AOP, includes an immediate operator action to verify that SWP-P2C started and that SWP-MOV40C and SWP-AOV599 opened. The verification steps are taken to mean that the operators would ensure that the pump started and the valves are open. If the valves did not open, the operator would take immediate steps to manually open the valves. In addition, the AOP includes a caution statement immediately before these actions that states that the HPCS Diesel will fail in one minute without jacket water cooling. This statement is conservative, but it emphasizes the need to open the SWP-AOV599 valve promptly. Therefore, the manipulation time is taken to be 30 seconds. The valve stroke time for SWP-AOV599 is 8 seconds.

The median response time is assumed to be 2-3 minutes based on the fact that opening the valve would be part of the immediate operator actions associated with a Station Blackout. Following a loss of offsite power, the control room lights would reduce to the emergency lights and the plant would scram. The operators would start the immediate operator actions associated with a loss of offsite power per AOP-0004. These actions would verify that a plant scram occurred, that the turbine tripped, and that the Emergency Diesel Generators started and began load sequencing. If the Division I and II EDG did not start, the operators would then go to AOP-0050 and start the immediate operator actions associated with Station Blackout. These actions would involve starting the RCIC system and if the HPCS diesel started, verifying that SWP-P2C, SWP-MOV40C and SWP-AOV599 functioned properly.

The failure probability for this operator action (SWP-HEEHFRAOV599) is 2.1E-1. This failure rate is based primarily on the cognitive response time. This probability is highly dependent on the time available to perform the action (5 minutes based on HPCS diesel trip without jacket water cooling) and the median response time for the crew to open SWP-AOV599 after an SBO occurs.

Summary of Updated Risk Information

BASELINE PSA REV. 3A

1. Summary of Risk Analyses

Level One (core damage) Analysis
Internal events CDF = 3.39E-6/year
LERF = 7.38E-9/yr
Shutdown CDF = 2.81E-6/yr (Rev. 3)
Configuration risk management tool: EOOS

2. Initiators - At Power Internal Events

Initiator ID	*Initiator Description*	*Percent of Internal Events CDF*
INI-T1[4]	Loss of Offsite Power	58.0%
INI-TNSW1	Loss of Normal Service Water	30.0%
INI-TCCP1	Loss of CCP	4.5%
INI-TRSS1	Loss of RSS #1 Leads	3.9%
INI-T3B1	Loss of Feedwater	3.2%
Misc.	Other	0.4%

3. Dominant Sequences - At Power Internal Events

Sequence Description	*CDF (/year)*
Loss of NSW with common cause failure of SSW cooling tower return valves	3.38E-7
LOOP with common cause failure of SSW cooling tower return valves	3.01E-7
Loss of NSW with common cause failure of three SSW pump discharge valves	2.08E-7
LOOP with common cause failure of three SSW pump discharge valves	1.85E-7
LOOP with common cause failure of the Div. I, Div. II & Div. III EDG's	1.83E-7
LOOP with failure of automatic signal to start SSW	1.16E-7
Loss of CCP with common cause failure of SSW cooling tower return valves	7.61E-8
Loss of NSW with common cause failure of SSW pumps	5.46E-8

[4] The Loss of Offsite Power initiating event frequency is 0.035/year per NSAC-166.

Summary of Updated Risk Information (continued)

EDG A (DIVISION I) OUT OF SERVICE

1. Summary of Risk Analyses

Level One (core damage) Analysis
Internal events CDF = 1.35E-5/yr
LERF = 4.39E-08/yr

2. Initiators - At Power Internal Events

Initiator ID	*Initiator Description*	*Percent of Internal Events CDF*
INI-T1	Loss of Offsite Power	80.8%
INI-TNSW1	Loss of Normal Service Water	7.6%
INI-TRSS1	Loss of RSS #1 Leads	6.6%
INI-TCCP1	Loss of CCP	2.3%
INI-T3A	Loss of Power Conversion System	1.1%
INI-T3B1	Loss of Feedwater	0.9%
Misc.	Other	0.7%

3. Dominant Sequences - At Power Internal Events

Sequence Description	*CDF(/year)*
LOOP with EDG A OOS and Division II battery charger fails	1.62E-6
LOOP with EDG A OOS and EDG B fails to run	5.58E-7
LOOP with EDG A OOS and EDG B fails to start	4.76E-7
Loss of NSW with EDG A OOS and common cause failure of SSW cooling tower return valves	3.38E-7
LOOP with EDG A OOS and common cause failure of SSW cooling tower return valves	3.01E-7
LOOP with EDG A OOS and PVLCS compressor fails to start, IAS Diesel compressor fails to start, and EDG C fails to run	2.65E-7
Loss of NSW with EDG A OOS and common cause of SSW pumps	2.08E-7
LOOP with EDG A OOS and common cause of SSW pumps	1.85E-7

Summary of Updated Risk Information (continued)

EDG B (DIVISION II) OUT OF SERVICE

1. Summary of Risk Analyses

Level One (core damage) Analysis
Internal events CDF = 1.05E-5/yr
LERF = 4.33E-08/yr

2. Initiators - At Power Internal Events

Initiator ID	*Initiator Description*	*Percent of Internal Events CDF*
INI-T1	Loss of Offsite Power	83.7%
INI-TNSW1	Loss of Normal Service Water	9.7%
INI-T3A	Loss of Power Conversion System	2.1%
INI-TCCP1	Loss of CCP	1.4%
INI-TRSS1	Loss of RSS #1 Leads	1.3%
Misc.	Other	1.8%

3. Dominant Sequences - At Power Internal Events

Sequence Description	*CDF(/year)*
LOOP with EDG B OOS and Division I battery charger fails	1.62E-6
LOOP with EDG B OOS and EDG A fails to run	5.58E-7
LOOP with EDG B OOS and EDG A fails to start	4.76E-7
Loss of NSW with EDG B OOS and common cause failure of cooling tower return valves	3.38E-7
LOOP with EDG B OOS and common cause failure of SSW cooling tower return valves	3.01E-7
Loss of NSW with EDG B OOS and common cause failure of cooling tower return valves	2.08E-7
LOOP with EDG B OOS and common cause failure of SSW cooling tower return valves	1.85E-7
LOOP with EDG B OOS and common cause failure of remaining 2 EDG's	1.83E-7

ATTACHMENT 5
Tier 1: Diesel Generator PSA Study Results

INTERNAL EVENTS ANALYSIS

Risk-informed support for the proposed TS changes to extend the allowed outage time (AOT) for either the Division I or Division II EDG is based upon PSA calculations performed to quantify the change in average CDF and average LERF resulting from the increased AOT.

To determine the effect of the longer AOT for restoration of an inoperable Division I or Division II EDG, the guidance suggested in RG 1.177 was used. Thus, the following risk metrics were used to evaluate the risk impacts of extending the EDG AOT from 72 hours to 14 days.

> ΔCDF_{AVG} is the change in the annual average CDF due to any increased on-line maintenance unavailability of EDGs that could result from the increased AOT. This risk metric is used to determine whether a change in CDF is regarded as risk significant compared against the criteria of RG 1.174. These criteria are a function of the baseline annual average core damage frequency, $CDF_{BASE.}$ In this study, it is assumed that one extended diesel generator outage occurs per cycle per division.
>
> $\Delta LERF_{AVG}$ is the change in the annual average LERF due to any increased on-line maintenance unavailability of EDGs that could result from the increased AOT. RG 1.174 criteria were also applied to judge the significance of changes in this risk metric.
>
> $ICCDP_Y$ is the incremental conditional core damage probability with EDG Y (Div I or Div II) out of service for the proposed AOT of 14 days. This risk metric is used as suggested in RG 1.177 to determine whether a proposed increase in AOT duration has an acceptable risk impact.
>
> $ICLERP_Y$ is the incremental conditional large early release probability with EDG Y (Div I or Div II) out of service for the proposed AOT of 14 days. RG 1.177 criteria were also applied to judge the significance of changes in this risk metric.

Attachment 4 provides the values for the Revision 3A at-power base CDF as well as the CDF for EDG A (Division I) being out of service (OOS) and EDG B (Division II) OOS. This information is summarized in the table below.

Metric	CDF
Baseline	3.39E-6/yr
EDG A OOS	1.35E-5/yr
EDG B OOS	1.05E-5/yr

The average at-power CDF with the change in the EDG AOT was computed by adding the CDF for the period during which the EDG is out of service (OOS) in the AOT with the CDF for the remainder of the cycle.

$\Delta CDF_{AT\text{-}POWER} = (T_A/T_{CYCLE})CDF_{AOOS} + (T_B/T_{CYCLE})CDF_{BOOS} + (1 - (T_A + T_B)/T_{CYCLE})CDF_{BASE} - CDF_{BASE}$

where

> CDF_{AOOS} is the CDF evaluated from the PSA model with the Division I EDG (EDG A) out of service and compensating measures for EDG A implemented. These compensating measures include prohibiting maintenance or inoperable status of any of the remaining two EDGs at the site as well as other compensating measures identified in this evaluation.
>
> CDF_{BOOS} is the CDF evaluated from the PSA model with the Division II EDG (EDG B) out of service and compensating measures for EDG B implemented. These compensating measures include prohibiting maintenance or inoperable status of any of the remaining two EDGs at the site as well as other compensating measures identified in this evaluation.
>
> T_A is the total time per fuel cycle (T_{CYCLE}) that EDG A is out of service for the extended AOT.
>
> T_B is the total time per fuel cycle (T_{CYCLE}) that EDG B is out of service for the extended AOT.
>
> CDF_{BASE} is the baseline annual average CDF with average unavailability of EDGs consistent with the current EDG on-line testing and maintenance.

The evaluation was performed based on the assumption that the full AOT would be applied once per EDG per refueling cycle, hence $T_A = T_B = 14$ days. The cycle time is based on the current 18 month fuel cycle (allowing for planned and unplanned outage time), which yields $T_{CYCLE} = 475$ days. In determining the values below, the PSA quantification truncation limit was set to 1.3E-9/yr for sequence quantification, more than 3 orders of magnitude below the total CDF. CDF_{AOOS} and CDF_{BOOS} were determined with the maintenance frequency for certain support systems set to zero. Specifically, the maintenance frequency for the remaining EDGs, HPCS, RCIC and the alternate train of SSW were set to zero. These systems would not be taken out of service for planned maintenance during extended planned maintenance on the Divisions I or II EDGs.

$$\begin{aligned}\Delta CDF_{AT\text{-}POWER} &= (T_A/T_{CYCLE})CDF_{AOOS} + (T_B/T_{CYCLE})CDF_{BOOS} + [1 - (T_A + T_B)/T_{CYCLE}]CDF_{BASE} - CDF_{BASE} \\ &= (14 \text{ days}/475 \text{ days}) * 1.35\text{E-}5/\text{yr} + (14 \text{ days}/475 \text{ days}) * 1.05\text{E-}5/\text{yr} \\ &\quad + [1 - (14 + 14 \text{ days})/475 \text{ days}] * 3.39\text{E-}6/\text{yr} - 3.39\text{E-}6/\text{yr}\end{aligned}$$

$$= 3.98E\text{-}7/yr + 3.09E\text{-}7/yr + 3.19E\text{-}6/yr - 3.39E\text{-}6/yr$$

$$= 5.07E\text{-}7/yr$$

The average shutdown CDF with the change in the EDG AOT was computed using the RF-10 outage schedule. The current schedule is for a 19 day outage with 5 days of EDG A OOS and 9 days of EDG B OOS. The baseline CDF for the shutdown PSA assumes 7 days with EDG A OOS and 10 days with EDG B OOS (as had originally been scheduled). In determining the values below, the PSA quantification truncation limit was set to 1.0E-9/yr for sequence quantification, more than 3 orders of magnitude below the total CDF.

$$\Delta CDF_{SHUTDOWN} = CDF_{AOOS\ 5\ days\ BOOS\ 9\ days} - CDF_{BASE}$$

$$= 2.81E\text{-}6/yr - 2.83E\text{-}6/yr$$

$$= -\ 2.0E\text{-}8/yr$$

Combining these provides the total change in average CDF.

$$\Delta CDF_{AVG} = \Delta CDF_{AT\text{-}POWER} + \Delta CDF_{SHUTDOWN}$$

$$= 5.07E\text{-}7/yr + (-2.0E\text{-}8/yr)$$

$$= 4.87E\text{-}7/yr$$

An approach similar to that used for the at-power CDF was used to determine the average at-power LERF.

The current revision to the River Bend Level 2 LERF is approximately 2.6E-8/yr. This includes the affect of PSA Level 1 Revision 3 and the removal of the IFTS blind flange for a total of sixty days. A detailed discussion of these changes is presented in RBS RAI responses and NRC SER dated July 3, 2001 (TAC NO. MA7827), which approved the IFTS blind flange removal. This evaluation will revise the current baseline LERF to account for the diesel generator AOT extension.

Given that the starting point for the Level 2 analysis is core damage, a change in core damage frequency (CDF) inherently changes the Level 2 analysis results. With the current Level 2 analysis, only a hydrogen burn or a failure of the containment isolation system resulting in a leakage path of one square foot or larger contribute to LERF. Additionally since a LERF is considered an early release, events that result in a large failure of containment eight hours or longer after the initiation of the event, are by definition not a LERF. MAAP analyses have shown that an uncontrolled hydrogen burn that occurs before vessel failure is not likely to cause a large containment failure due to the limited amount of hydrogen released in the containment. Additionally, the MAAP analyses have demonstrated that it takes approximately five hours from core damage to vessel failure. Therefore, LOOP and SBO events that result in core damage three hours or more after the initiation of an event will not contribute to LERF. The Level 2 containment event tree and decomposition event trees were reviewed and it was determined using engineering judgement that these trees are unaffected by the changes associated with the Level 1 revision. Therefore, the binning of the core damage states will be the same as with the previous analysis.

In the current Level 2 analysis approximately 4.0% of short-term SBO events (i.e., SBO that result in core damage within 3 hours) result in a LERF, 0.19% of short-term LOOP events result in a LERF, and 0.14% of all other events (transients) result in LERF. As stated above, this distribution is not changed by the Level 1 revision. Therefore, the new LERF numbers are obtained by multiplying revised short-term SBO, short-term LOOP and transient events by these percentages. The table below summarizes the current and revised LERF values.

REVISION 3 PSA

CDF Initiator	CDF Frequency	LERF Frequency	Multiplier
Short-Term SBO	6.08E-7/yr	2.38E-8/yr	~4.0%
Short-Term LOOP (non-SBO)	1.87E-7/yr	3.51E-10/yr	~0.19%
Transient	1.96E-6/yr	2.66E-9/yr	~0.14%
Total	9.45E-6/yr	2.68E-8/yr	N/A

REVISION 3A BASELINE PSA

CDF Initiator	CDF Frequency	Multiplier	LERF Frequency
Short-Term SBO	1.34E-7/yr	4.0%	5.36E-9/yr
Short-Term LOOP (non-SBO)	1.30E-8/yr	0.19%	2.47E-11/yr
Transient	1.42E-6/yr	0.14%	1.99E-9/yr
Total	3.39E-6/yr	N/A	7.38E-9/yr

EDG A OUT OF SERVICE

CDF Initiator	CDF Frequency	Multiplier	LERF Frequency
Short-Term SBO	8.87E-7/yr	4.0%	3.55E-8/yr
Short-Term LOOP (non-SBO)	2.49E-6/yr	0.19%	4.73E-9/yr
Transient	2.59E-6/yr	0.14%	3.63E-9/yr
Total	1.35E-5/yr	N/A	4.39E-8/yr

EDG B OUT OF SERVICE

CDF Initiator	CDF Frequency	Multiplier	LERF Frequency
Short-Term SBO	9.97E-7/yr	4.0%	3.99E-8/yr
Short-Term LOOP (non-SBO)	5.43E-7/yr	0.19%	1.03E-9/yr
Transient	1.71E-6/yr	0.14%	2.40E-9/yr
Total	1.05E-5/yr	N/A	4.33E-8/yr

Note that the increase in LERF is not directly proportional to the increase in CDF. This is due to the change in importance of short-term SBO in the revised CDF. A larger fraction of short-term SBO events contribute to LERF since in these events the igniters are unavailable due to a loss of all safety-related power (i.e., a hydrogen burn is more likely).

The maximum increase in LERF is approximately a factor of 6. However, this LERF is based on the instantaneous CDF for having a diesel out of service. The incremental LERF value will be significantly less since the diesel AOT extension is only 14 days per operating cycle.

$$\Delta LERF_{AVG} = (T_A/T_{CYCLE})LERF_{AOOS} + (T_B/T_{CYCLE})LERF_{BOOS} + (1 - (T_A + T_B)/T_{CYCLE})LERF_{BASE} - LERF_{BASE}$$

where

$LERF_{AOOS}$ is the LERF evaluated from the PSA model with Division the I EDG (EDG A) out of service and compensating measures for EDG A implemented. These compensating measures include prohibiting maintenance or inoperable status of any of the remaining two EDGs at the site as well as other compensating measures identified in this evaluation.

$LERF_{BOOS}$ is the LERF evaluated from the PSA model with the Division II EDG (EDG B) out of service and compensating measures for EDG B implemented. These compensating measures include prohibiting maintenance or inoperable status of any of the remaining two EDGs at the site as well as other compensating measures identified in this evaluation.

T_A is the total time per fuel cycle (T_{CYCLE}) that EDG A is out of service for the extended AOT.

T_B is the total time per fuel cycle (T_{CYCLE}) that EDG B is out of service for the extended AOT.

$LERF_{BASE}$ is the baseline annual average LERF with average unavailability of EDGs consistent with the current EDG on-line testing and maintenance.

The evaluation was performed based on the assumption that the full AOT would be applied once per EDG per refueling cycle, hence $T_A = T_B = 14$ days. The cycle time is based on the current 18 month fuel cycle (allowing for planned and unplanned outage time), which yields $T_{CYCLE} = 475$ days. The change in the annual average CDF because of the change in the EDG AOT was evaluated by computing the change in the at-power CDF and the change in the shutdown CDF. However, since RBS does not have a Level 2 evaluation for shutdown, the change in LERF is computed for at-power conditions only.

$\Delta LERF_{AVG} = (T_A/T_{CYCLE})LERF_{AOOS} + (T_B/T_{CYCLE})LERF_{BOOS} + (1 - (T_A + T_B)/T_{CYCLE})LERF_{BASE} - LERF_{BASE}$

$= (14\ d/475\ d)4.39E\text{-}8/yr + (14\ d/475\ d)4.33E\text{-}8/yr + (1\text{-}\ (2 * 14\ d)/475\ d) * 7.38E\text{-}9/yr - 7.383E\text{-}9/yr$

$= 1.29E\text{-}9/yr + 1.28E\text{-}9/yr + 6.95E\text{-}9/yr - 7.38E\text{-}9/yr$

$= 2.14\text{-}9/yr$

The incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) are computed using their definitions in RG 1.177. In terms of the above defined parameters, the definition of ICCDP is as follows:

$ICCDP_Y = (CDF_{YOOS} - CDF_{BASE}) * T_{AOT}$

For this evaluation, the CDF for EDG A was used since this value bounds the CDF with EDG B out of service.

$ICCDP_Y = (CDF_{YOOS} - CDF_{BASE}) * (14\ days)/(365\ days/year)$

Note that in the above formula, 365 days/year is merely a conversion factor to get the Allowed Outage Time units consistent with the CDF frequency units. The ICCDP values are dimensionless probabilities to evaluate the incremental probability of a core damage event over a period of time to the extended allowed outage time. This should not be confused with the evaluation of $\Delta CDF_{AVG.}$

$ICCDP_Y = (CDF_{YOOS} - CDF_{BASE}) * (14\ days)/(365\ days/year)$

$= (1.35E\text{-}5/year - 3.39E\text{-}6/year) * (14\ days)/(365\ days/year)$

$= 3.88E\text{-}7$

Similarly, ICLERP is defined as follows.

$ICLERP_Y = (LERF_{YOOS} - LERF_{BASE}) * T_{AOT}$

$= (4.39E\text{-}8/year - 7.38E\text{-}9/year) * (14\ days)/(365\ days/year)$

$= 1.40E\text{-}9$

The results of the risk evaluation are presented in the table below.

Risk Metric	Significance Criterion[5]	RBS Results
ΔCDF_{AVG}	<1.0E-06/yr	4.87E-7/yr
ICCDP	<5.0E-07	3.88E-7
$\Delta LERF_{AVG}$	<1.0E-07/yr	2.14E-9/yr
ICLERP	<5.0E-08	1.40E-9

Note that these estimates are obtained using the RBS Level 1 Internal Events PSA model that does not include contributions from internal fires, seismic events and other external events. However, due to the relatively low frequency of these events as compared to that expected from internal initiators and the significant capability of the plant to cope with these events (e.g., SSE design criterion and substantial separation used in the design of the plant), inclusion of fires and external events would not impact the conclusions of this evaluation.

EXTERNAL INITIATING 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 (HFO) events were adequately addressed.

RBS developed a Fire PSA to address the fire portion of the IPEEE. 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

[5] Reference RG 1.174 & RG 1.177

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[6].

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 EDG 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.

[6] 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 EDG 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. However, since this discrimination was not known, this assumption was applied.

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

The CDF for the MCR non-evacuation scenarios for fires in non-divisional cabinets was 1.62E-8/yr while the CDF for MCR fires that result in evacuation was 3.70E-6/yr.

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 EDGs 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.

UNCERTAINTY ANALYSIS

An uncertainty analysis was completed for the At-Power PSA using the code Uncert Version 2.2. The results are summarized below:

	Point Estimate	Mean	5%	95%
Baseline	3.39E-6	3.11E-06	6.64E-07	8.34E-06

TRANSITION RISK

Transition risk refers to the risk associated with changing the operating mode of a BWR from its nominal full-power operating state to a lower power shutdown state. Transition risk issues are important when a reactor has to be shut down due to inoperable equipment. Transition risk is defined as the Core Damage Probability (CDP) associated with the transition of the plant from full-power operation to plant shutdown and back to full power.

For this evaluation, transition risk can be evaluated by comparing the conditional core damage probabilities for the following two sequences:

1) Shutting down the plant to repair the OOS EDG (INI-T3A)

2) At-Power Risk with the EDG OOS for 14 days

Assumptions:

1. The Level 1 PSA model is sufficient to capture the risk of transitioning to Hot Shutdown (Mode 3).
2. EDG A OOS is bounding for both scenarios.

Based on the current TS requirements, the plant would remain at power for 72 hours (3 days) then transition to hot shutdown in 12 hours and cold shutdown in 36 hours. Assuming a total repair time of 14 days, the plant would remain in cold shutdown a total of 9.5 days. The following time line summarizes the transition to cold shutdown:

```
t = 0                        t = 72 hours   t = 84 hours           t = 108 hours                 t = 14 days
|----------------------------|-----------------|---------------------------|------------------------------------------|
 72 hour AOT                 Transition to         Transition to                      Cold Shutdown
                             Hot Shutdown          Cold Shutdown
```

t = 0 to 72 hours

To evaluate the risk of an EDG OOS at power for 72 hours, the incremental risk for the duration that the plant is in this condition is calculated. This risk is calculated as follows:

Incremental Risk = (Instant. CDF/year – base CDF/year) * duration (days) /365 d/yr.

The RBS baseline CDF is 3.39E-6/year. With EDG A OOS, the CDF is 1.35E-5/yr. Assuming a 72 hours out of service period, the incremental risk is:

Incremental Risk = (1.35E-5/year – 3.39E-6/year)(3 days/365days/yr) = 8.31E-8 CCDP

t = 72 hours to 84 hours

For the controlled reactor shutdown to Hot Shutdown, INI-T3A, Transient with the Power Conversion System (PCS) Available, is most representative of the plant shutdown sequence. No other transients are assumed to occur concurrent with the controlled shutdown. For this evaluation INI-T3A is set to TRUE and all other initiators are set to FALSE. EDG A is taken out of service since it is the bounding case. Using EOOS, the transition risk is calculated to be:

Risk Due to Shutdown = 2.64E-7 CCDP

t = 84 hours to 108 hours

RBS uses the At-Power EOOS model for evaluating risk during hot shutdown. Therefore, similar to the period from 0 to 72 hours, the risk of an EDG OOS for 24 hours at hot shutdown is the incremental risk for the duration that the plant is in this condition. This risk is calculated as follows:

Incremental Risk = (Instant. CDF/year – base CDF/year) * duration (days) /365 d/yr.

The RBS baseline CDF is 3.39E-6/year. With EDG A OOS, the CDF is 1.35E-5/yr. Assuming a 72 hours out of service period, the incremental risk is:

Incremental Risk = (1.35E-5/year – 3.39E-6/year)(1 days/365days/yr) = 2.77E-8 CCDP

t = 108 hours to 14 days

The risk at the point of cold shutdown is assumed to be comparable to the baseline risk for the refueling outage, which is 2.81E-6./yr (this number would be lower for a forced outage without the additional outage related maintenance activities). At approximately 24 hours in the schedule, EDG A is taken OOS for maintenance. The risk at that point is 2.84E-6/yr. The risk from the point of cold shutdown to power ascension is equal to the incremental risk for the duration that the plant is in this condition. Incremental risk is calculated as follows:

Incremental Risk = (Instant. CDF/year – base CDF/year) * duration (days) /365 d/yr

Assuming a total of 14 days to repair the EDG, the risk during shutdown would be:

Incremental Risk = (2.84E-6/year – 2.81E-6/year)(9.5 days/365days/yr) = 7.8E-10 CCDP

Thus, the transition risk to shutdown and repair the EDG would be:

Transition Risk = 8.31E-8 + 2.64E-7 + 2.77E-8 + 7.8E-10 = 3.76E-7 CCDP

To evaluate the risk of repairing an EDG at power for 14 days, the incremental risk for the duration that the plant is in this condition is calculated. This risk is calculated as follows:

Incremental Risk = (Instant. CDF/year – base CDF/year) * duration (days) /365 d/yr

The RBS baseline CDF is 3.39E-6/year. With EDG A OOS, the CDF is 1.35E-5/yr. Assuming a 14 day out of service period, the incremental risk is:

Incremental Risk = (1.35E-5/year - 3.39E-6/year)(14 days/365days/yr) = 3.88-7 CCDP

Based upon a comparison of the transition risk if the plant were shutdown to repair the EDG to the risk if the plant were to repair the EDG on-line, it can be seen that the two sequences result in comparable risk.

Attachment 6

Markup of Current
Technical Specification pages

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources—Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electric Power Distribution System; and

b. Three diesel generators (DGs).

APPLICABILITY: MODES 1, 2, and 3.

---------------------------NOTE---------------------------
Division III AC electrical power sources are not required to be OPERABLE when High Pressure Core Spray System and Standby Service Water System pump 2C are inoperable.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 Restore required offsite circuit to OPERABLE status.	72 hours <u>AND</u> 24 hours from discovery of two divisions with no offsite power <u>AND</u> 17 6 days from discovery of failure to meet LCO
B. One required DG inoperable.	B.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	B.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	<u>AND</u>	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.3.1 Determine OPERABLE DG(s) are not inoperable due to common cause failure. OR B.3.2 Perform SR 3.8.1.2 for OPERABLE DG(s). AND B.4 Restore required DG to OPERABLE status.	24 hours 24 hours Insert A ~~72 hours~~ ~~AND~~ ~~6 days from discovery of failure to meet LCO~~
C. Two required offsite circuits inoperable.	C.1 Declare required feature(s) inoperable when the redundant required feature(s) are inoperable. AND C.2 Restore one required offsite circuit to OPERABLE status.	12 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s) 24 hours

(continued)

INSERT A

72 hours from discovery of an inoperable Division III DG

<u>AND</u>

14 days

<u>AND</u>

17 days from discovery of failure to meet LCO

Attachment 7

Markup of Current
Technical Specification Bases Pages
(For Information Only)

BASES

ACTIONS (continued)

A.2

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours.

This Completion Time assumes sufficient offsite power remains to power the minimum loads needed to respond to analyzed events. In the event one or more division is without offsite power, this assumption is not met. Therefore, the optional Completion Time is specified. Should two (or more) divisions be affected, the 24 hour Completion Time is conservative with respect to the Regulatory Guide assumptions supporting a 24 hour Completion Time for both offsite circuits inoperable. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E distribution system.

The Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The third Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days ~~72 hours~~. This situation could lead to a total of 17 days ~~144 hours~~, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 14 days ~~72 hours~~ (for a total of 31 days ~~9 days~~) allowed prior to complete restoration of the LCO. The 17 day ~~6 day~~ Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 14 day ~~6 day~~ Completion Times means that both

(continued)

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DG(s).

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the Condition Report Program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

B.4

~~According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours.~~ ~~In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system.~~ Insert B The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period. Insert C

The ~~second~~ third Completion Time for Required Action B.4 established a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of ~~144 hours~~ 17 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of ~~9~~ 20 days) allowed prior to complete restoration of the LCO. The ~~6~~ 17 day Completion Time provides a limit on the time allowed in a specified

(continued)

BASES

ACTIONS

B.4 (continued)

condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the ~~72 hour and 6 day~~ Completion Times means that ~~both~~ the three Completion Times apply simultaneously, and the ~~more~~ most restrictive Completion Time must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered.

C.1 and C.2

Required Action C.1 addresses actions to be taken in the event of concurrent failure of redundant required features. Required Action C.1 reduces the vulnerability to a loss of function. The rationale for the 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety divisions are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related divisions (i.e., single division systems are not included in the list, although, for this Required Action, Division III is considered redundant to Division I and II ECCS. Additionally, the Division III powered SSW pump 2C is considered redundant to SSW pumps 2B and 2D powered from Division II). Redundant required features failures consist of any of these features that are inoperable, because any inoperability is on a division redundant to a division with inoperable offsite circuits.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required

(continued)

INSERT B

Although Condition B applies to a single inoperable DG, several Completion Times are Specified for this Condition.

The first Completion Time applies to an inoperable Division III DG.

INSERT C

This Completion Time begins only "upon discovery of an inoperable Division III DG" and, as such, provides an exception to the normal "time zero" for beginning the allowed outage time "clock" (i.e., for beginning the clock for an inoperable Division III DG when Condition B may have already been entered for another equipment inoperability and is still in effect).

The second Completion Time (14 days) applies to an inoperable Division I or Division II DG and is a risk-informed allowed out-of-service time (AOT) based on a plant specific risk analysis. The extended AOT would typically be used for voluntary planned maintenance or inspections but can also be used for corrective maintenance. However, ~~U~~use of the extended AOT for voluntary planned maintenance should be limited to once within an operating cycle (18 months) for each ~~E~~DG (Division I and Division II). Additional contingencies are to be in place for any extended AOT duration (greater than 72 hours and up to 14 days) as follows:

1. An ~~E~~DG extended AOT will not be entered for voluntary planned maintenance purposes if severe weather conditions are expected.
2. The condition of the offsite power supply and switchyard, including transmission lines and ring bus breakers, will be evaluated.
3. No elective maintenance will be scheduled within the switchyard that would challenge offsite power availability during the proposed extended ~~E~~DG AOT.
4. Operating crews will be briefed on the ~~E~~DG work plan, with consideration given to key procedural actions that would be required in the event of a LOOP or SBO.
5. High pressure injection systems will not be taken OOS for maintenance while ~~E~~DG Division ~~A~~I or II~~B~~ is out of service for extended maintenance.